A Report on the Marketing of British Columbia Natural Gas

George W. Govier
Chairman

February, 1983

Victoria
British Columbia

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Natural Gas Marketing Study

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January 24, 1983

Mr. Roy Illing
Deputy Minister
Energy, Mines and Petroleum Resources
Province of British Columbia
Parliament Buildings
VICTORIA, B.C.
V8V 1X4

Dear Mr. Illing:

REPORT OF STUDY GROUP ON THE MARKETING OF
BRITISH COLUMBIA NATURAL GAS

The Study Group composed of Messrs. D.H. Horswill, M.M. Moseley, A.G.T. Weaver and myself, as Chairman, has now completed the assignment given to it by the Minister of Energy, Mines and Petroleum Resources through the contract dated August 1, 1982 with Govier Consulting Services Ltd. I have pleasure in tendering herewith the Report of the Study Group, complete except for Appendices 5,7,8 and 9 and those portions of Section 3 dependent thereon. These appendices on the details of the producer netbacks, the proposed royalty system and the financial implications to the industry, the consumers of natural gas in British Columbia and the Government are being reviewed for numerical accuracy and will be forwarded to you in a few days.

The Study Group acknowledges the assistance provided to it by the General Manager and staff of the BCPC, the staff of the Ministry and the consulting firm DataMetrics of Calgary. Additionally, the Study Group expresses its appreciation to the members of the industry and others who could be affected by its recommendations for their helpful responses to its request for advice.

Given the complexity of the matters dealt with, the Study Group believes there would be merit in making its report public, in whole or in part, and for the Government to invite comment from persons who would be affected by the recommendations provided that this not be permitted to delay unduly the Government's decisions and actions.

Yours sincerely,

G.W. Govier
Chairman
Study Group on the Marketing of
British Columbia Natural Gas

EXECUTIVE SUMMARY

The Study Group on the marketing of British Columbia natural gas established by the Minister of Energy, Mines and Petroleum Resources in September, 1982 has completed its broad review of the systems of developing and marketing natural gas in British Columbia, Alberta and Saskatchewan. Following on this, it has developed a series of recommendations designed to stimulate exploration, development and marketing of British Columbia natural gas.

The Study Group recognizes that current economic conditions and particularly the modest demand for Canadian natural gas in the western part of the United States, preclude any large and early expansion of sales of British Columbia gas. It is also aware that a number of the problems facing the British Columbia natural gas industry cannot be solved easily or immediately. Accordingly, in developing its recommendations, the Study Group has focussed on the changes required in the system of developing and marketing natural gas to enable British Columbia to take maximum advantage not only of any immediate opportunities which may be developed but of those of the intermediate and long term future.

In its review of the present systems of development and marketing natural gas in the three provinces, the Study Group notes that British Columbia producers, unlike those in Alberta, do not have the opportunity to construct or arrange for the construction of raw gas transmission or processing facilities. British Columbia producers, being required to sell their gas in its raw state to the British Columbia Petroleum Corporation (BCPC), are unable to retain ownership and the right to negotiate the sale of the marketable gas and any by-products. Additionally, the BCPC sells the raw gas it acquires exclusively to Westcoast Transmission Company Limited (Westcoast) who transports the marketable gas and is its sole marketer. This again is in contrast to the system in Alberta where NOVA, the

principal transporter, is not a marketer and the producer may sell his marketable gas to a number of purchasers. Furthermore, the processing and transmission of British Columbia gas within the province, because it is carried out by the same company which buys and sells gas interprovincially and internationally, is under the jurisdiction of the National Energy Board. In both Alberta and Saskatchewan, these operations are under provincial jurisdiction.

British Columbia's system of wholesale and field pricing of natural gas is also unique with both prices being fixed by Cabinet order and not being directly related through the transmission cost of service. In lieu of a royalty, British Columbia, through the BCPC, retains the difference between the wholesale price less Westcoast's cost of service and the net field price received by the producer. The latter has not provided netbacks to the producers which are comparable to those received by producers in Alberta. This is one reason why British Columbia, relative to its geological prospects, has seen a decline in exploration actvity in the last two years.

The Study Group's recommendations relate principally to seven areas:

1 broadening the future opportunities of the producers, to construct facilities and to market gas and by-products;

2 focusing the future primary activities of the BCPC on marketing and away from revenue collection;

3 providing that Westcoast, respecting its intra-provincial processing and transmission of British Columbia gas, act as a common purchaser and common carrier, and in due course, be brought under provincial control;

4 providing a rational, reasonably predictable system for fixing the average wholesale price of natural gas in the province;

5 providing that retail prices for gas will reflect the full delivered cost of service with any government subsidy being made by way of an explicit grant;

6 providing that the field price of British Columbia gas be determined by deducting the appropriate cost of service from the wholesale price and adding an increment covering export and by-product sales; and

7 instituting an explicit royalty system in which the royalty paid by a producer would be generally sensitive to his costs and the total price including the 'flowback' received for his gas and any by-products.

The Study Group believes that its recommendations referred to in items (1), (2), and (3) will lead to more innovative and aggressive marketing which will eventually result in expanded sales of British Columbia gas. It also believes that the pricing and 'flowback' system it proposes, together with the recommended royalty system, will lead to producer netbacks at the levels required to attract exploration activity and, as markets are found, to facilitate the development of new fields, and gathering, processing and transmission facilities. Equally important, it is expected that the proposed pricing/royalty system will result in reasonable prices to British Columbia consumers and increasing revenues to the government.

A number of specific and in some cases interrelated recommendations are offered in connection with the seven main areas referred to above. These are discussed in Section 3 and Appendices 5 to 9 of the report. They are also given without discussion in the Listing of Recommendations on Pages 7 to 15.

Listing of Principal Recommendations

In this Listing of Recommendations the Study Group isolates the recommendations presented in the report and gives these in broad terms. Discussion and more detail are given in Section 3 and Appendices 5 to 9.

3.2 Development of Natural Gas Supply

1 That the government seek guarantees from Westcoast over and above those that exist in the Westcoast/ BCPC agreement that British Columbia gas producers will always be offered the first right to purchase contracts for gas to be delivered through the Westcoast system in British Columbia.

2 That efforts be continued to develop market alternatives for the Alberta supply entering into northeast British Columbia so as to permit more British Columbia gas to be sold in the United States export market.

3 That, in respect of gas now under existing contracts, the present gathering, processing and transmission system remain as is.

4 That, in respect of future contracted gas a producer have the following options:

(a) to sell raw gas at the field gathering point to any buyer (this would be similar to but less restrictive than the current arrangement where the producer sells raw gas to BCPC); and

(b) to retain ownership of raw gas, arranging for its transmission (by producer-owned or other facilities) to a gas processing plant (producer-owned or otherwise), and sell marketable gas to any buyer and any by-products to any buyers; where transmission or processing

facilities were owned by other than the producer he would pay a fee reflecting the costs involved. If Westcoast provides such service it should recover its full costs and any return thereon. This would require that Westcoast act as a common carrier and common processor.

5 That any future straddle plants in British Columbia should be built, owned and operated under exclusive provincial jurisdiction. The implementation of this recommendation is related to recommendations discussed under Section 3.3.2 respecting the regulation of Westcoast.

6 That, in the case of downstream storage, the Ministry consider re-posting Crown petroleum and natural gas rights in the Fraser Valley in order to promote early exploration drilling which could also result in the discovery of a reservoir suitable for gas storage.

7 That the Ministry also invite requests for exploration permits from parties interested in underground storage only.

3.3 Marketing Arrangements

8 That, in the case of gas which has been or will be purchased for the purpose of meeting existing contracts of service, the present marketing arrangements remain in place.

9 That, in the case of future contracted gas, producers have the options of selling raw gas or retaining ownership of raw gas to permit their direct involvement in the marketing of the resulting marketable gas and its by-products (subject only to a limited restriction respecting the marketing of sulphur).

10 That producers have the option of marketing future contracted gas, either raw or marketable, through the BCPC or Westcoast or any other buyer, or to pay the commissions to others who would market gas as agents, as described in Section 3.3.2.

11 That, if favoured by producers, a committee be established by the Ministry, with representation from the BCPC, Westcoast and producers, to provide advice respecting gas marketing.

12 That Westcoast's role under its existing contracts be continued until such time as the contracts expire.

13 That Westcoast continue to be the sole and exclusive owner and operator of existing pipeline and processing facilities.

14 That Westcoast act as a common carrier and processor for future contracted gas.

15 That Westcoast be given a non-exclusive right to purchase, gather, process and market future contracted gas and to receive commissions or fees for gathering, processing or marketing such gas that would reflect the true cost of service of transporting and processing the raw gas.

16 That the provincial government continue to make representations to the NEB respecting the necessity of a take-or-pay obligation on Northwest Pipeline for the purposes of the existing export Licence GL-41.

17 That the government endorse the representations that producers intend to make to the NEB in support of having Westcoast's taxation accounted for on a 'flow through' rather than 'normalized' basis.

18 That the Ministry, and the AGBC be charged with investigating ways and means, including seeking the advice and cooperation of Westcoast, the NEB, the federal government and any other concerned party to bring Westcoast's activities in gathering, processing and transporting British Columbia gas within the province under provincial control.

19 That the BCPC continue to act as the purchaser of raw gas under existing contracts and as the seller to Westcoast under the Basic Agreement with Westcoast.

20 That the BCPC continue its role in monitoring Westcoast's cost of service and making appropriate submissions thereon to the NEB, so long as the NEB retains jurisdiction over Westcoast's utility functions.

21 That the BCPC be given the opportunity but not the exclusive right to purchase future contracted gas on the basis that the price specified in such contracts of purchase would reflect the true cost of service of transporting and processing the raw gas.

22 That the BCPC acquire a temporary ownership position in future contracted gas to safeguard British Columbia's jurisdictional interests.

3.4 Pricing and Related Matters

23 That prices of natural gas at the wholesale or field level be expressed in $ per GJ.

24 That the system average wholesale price of natural gas move immediately to equal the Alberta border price for the years 1983 and 1984 (i.e. from $1.81/Mcf currently to $2.65/MMBTU in 1983 and $3.15/MMBTU in 1984).

25 That commencing in 1985 the system average wholesale price move in equal yearly steps to a minimum of 65 percent of the energy-equivalent cost of crude oil at the Vancouver refinery gate by 1990 so that:

(a) producer netbacks achieve the levels recommended in Section 3.12 when calculated under the royalty scheme recommended in Section 3.6;
(b) consumer retail prices after any provincial subsidy be at acceptable levels; and
(c) reasonable provincial revenue goals be met.

26 That, if circumstances change and the federal government revises its 65 percent figure that the province also review this matter in light of the particular circumstances existing at that time.

27 That the price at the gathering point for marketable natural gas sold intraprovincially, be a price derived by deducting the appropriate cost of service from the system average wholesale price.

28 That an export flowback scheme be instituted to allow all producers to share in the benefits from the export market ratably in proportion to their production of marketable gas.

29 That steps be taken to base prices for Alberta and Territories gas now being exported through British Columbia to the United States on a weighted average price received by producers of British Columbia gas from their total sales of marketable gas.

30 That the provincial government adopt the position and urge the federal government to accept that the present rigid export pricing system be replaced by a system where producers or producer's agents would negotiate with export buyers, on an arms-length

basis, the terms of export contracts which would then be subject to approval of the provincial and federal governments. These terms would include, among other matters, volume, price, take-or-pay commitments, peak day and annual deliveries, and duration. In their separate reviews of the export 'contract package' the provincial and federal governments would have regard for the public interest involved, the perceived commodity value of the gas, the price to Canadians, the cost of service and other relevant matters. Only those 'contract packages' which met such tests would be approved.

31 That the government request the BCUC to design an appropriate tariff structure for the allocation of Westcoast's cost of service along the lines recommended in its "1980 Natural Gas Price Inquiry Report".

3.5 New Market Development

32 That direct industrial sales would be authorized only where:

(a) the customer requires gas at prices below the utility gas rates;
(b) producers are prepared to sell at a discount; and
(c) the utility company franchised to serve the area in which the industrial customer is located maintains all rights to carry the gas and recover its full cost of service.

33 That the provincial government:

(a) continue to develop new markets for gas (e.g. CNG) and to protect existing markets;
(b) review the Gas Extension Assistance Program to determine whether it should be extended to other areas of the province; and

(c) continue to emphasize further processing of natural gas as an element of its industrial/ economic development policy.

3.6 Royalties

34 That British Columbia, at the earliest opportunity, introduce the proposed explicit royalty system.

35 That the royalty system be applied to all gas produced in the province including gas sold to the BCPC under existing contracts.

36 That the royalty payments be collected by the Ministry.

37 That the Ministry, in consultation with producers, the BCPC and Westcoast, develop a suitable method by which both the revenue from by-product sales and the cost of service can be allocated to producers and included in the total field price for royalty purposes.

38 That the Ministry work with the BCPC to develop the most practicable way to bring by-product revenues from gas under existing contracts under the royalty scheme.

3.7 Provincial Taxes

39 That British Columbia continue its current practice of providing income tax rebates for royalty payments.

3.8 Federal Taxes

40 That the province continue to urge the federal government to abandon both the COSC and NGGLT or, as a minimum, to reduce their negative impact on market expansion for natural gas.

3.10 Provincial Producer Incentives

41 That the province introduce a royalty holiday of 24 producing months for qualifying wells. Qualifying wells would be those drilled in the 12 months starting at the date of the implementation of this recommendation and which are classified as exploratory wells under the Petroleum and Natural Gas Act, R.S.B.C. 1979, c. 323. (Based on reasonable assumptions respecting the number of wells to be drilled and reserve additions, the value of the royalties foregone due to this incentive recommendation would be in the order of $20 million, spread over the late 1980's.)

3.12 Producer Netbacks and Equivalent Netbacks

42 That by 1985 producer netbacks be increased towards a target level of $0.90 per Mcf for post November 1973 gas and $0.55 per Mcf for all other gas in order to stimulate drilling activity in the province to greater than 300 wells per year.

3.13 Provincial Consumer Subsidy or Rebate

43 That an explicit consumer subsidy, in the form of a government grant or rebate to gas customers, be introduced as necessary to ensure that consumer gas rate increases for 1983 remain within the guidelines of the Rate Increase Restraint Act, S.B.C. 1982, c. 77.

44 That, after 1983, if the government decides to continue consumer subsidies, they be made by explicit grant and not at the expense of the wholesale price.

45 That all subsidies be paid to the consumer either directly or through the distribution utility.

3.14 Provincial Consumer Price

46 That the retail rates for natural gas continue to be determined by the BCUC at levels equal to the wholesale price specified in Section 3.4, plus the appropriate distributor cost of service. (The final consumer price would be the retail rate less any subsidy.)

In giving consideration to these recommendations it should be noted that there is a high degree of interdependence between them. The Study Group therefore further recommends that this interdependence be taken into account when the matters proposed in Section 3 are being considered and, if accepted, being implemented.

1.0 Introduction

1.1 Background

British Columbia's natural gas is a strategic resource which, through proper management, can make an important contribution to the province's economy. The government's stated policy is to ensure that British Columbia's natural gas resource is developed to achieve the maximum benefit for the people of the province. In this regard, the government has placed great emphasis on:

i) stimulation and expansion of markets for British Columbia natural gas; and
ii) stimulation of exploration and development in the petroleum and natural gas industry in British Columbia with the attendant benefits to the industry and province as a whole.

The province has experienced a marked decline in natural gas exploration and development in the past two years due to a number of factors affecting the profit potential of the industry and the limitations on investment capital in the current economic climate. One of the major factors has been the serious decrease in export sales in recent years. Total export sales under Licence GL-41 have fallen from 154 Bcf in 1980 to 92 Bcf in 1982. In turn, drilling activity in British Columbia dropped to 85 wells in 1982 compared with 385 in 1980. The provincial revenue from bonus bids has also been dramatically reduced from $181 million in 1980 to $17.0 million in 1982.

Since the release of its February 1980 statement on energy policy, the government of British Columbia has introduced a number of programs and initiatives respecting natural gas. These include grants for pipeline extensions in northeastern British Columbia and for promotion of compressed natural gas

(CNG) as a substitute motor fuel. The government has also invited interested parties to submit proposals to extend natural gas service to Vancouver Island.

In June 1981, the government announced an inquiry to assess the extent of British Columbia's natural gas surplus. This was completed and reported upon in June 1982. Following this, the government allocated British Columbia's surplus gas to liquified natural gas (LNG) exports, pipeline exports, and ammonia-urea projects.

In September, 1982, the Ministry of Energy, Mines and Petroleum Resources directed that a study of all critical aspects of marketing British Columbia's natural gas be undertaken. A Study Group was created for this purpose and this Report represents the views of the Study Group on the matters raised in its Terms of Reference. Members of the Study Group were: Dr. G.W. Govier, Chairman; Mr. M.M. Moseley, Mr. A.G.T. Weaver and Mr. D.H. Horswill. The Group received support from Ministry staff and consultants.

1.2 Terms of Reference

The Terms of Reference, the full text of which is reproduced in Appendix 1, specified that the Study Group was to:

(i) review the policies, system, and procedures in British Columbia compared to those in Saskatchewan and Alberta, including the impact of external regulatory authorities, relating to the intraprovincial and the extraprovincial marketing of natural gas, including the sale of gas by producers, the gathering, processing, and transportation of natural gas, and the resale of marketable natural gas; and

(ii) develop recommendations relating to the supply and marketing of British Columbia natural gas and, in particular, the matters reviewed under item (i) above.

The recommendations were to be provided in a report submitted to the Minister of Energy, Mines and Petroleum Resources.

1.3 Discussion and Approach

In accordance with its Terms of Reference, the Study Group conducted a review of the institutional framework covering all major facets of exploration, production, gathering, processing, transmission, royalties, pricing, taxation and marketing of natural gas. This review ranged from the disposition of Crown mineral resources through to the marketing of gas to the ultimate consumer. The mechanics of distribution and the distributor's utility-based rate schedules were not considered to be within the terms of reference of the study.

In addition to the comparisons required with Alberta and Saskatchewan, the Study Group undertook a comparison with respect to the relevant aspects of Canada Lands legislation.

To aid in its deliberations, the Study Group sought the comments of 21 companies and associations which could be affected by its recommendations (see Appendix 3.) The responses to this letter were of great assistance to the Study Group and are gratefully acknowledged.

Part 2 of the report highlights the present systems for the development and marketing of natural gas in British Columbia, Alberta and Saskatchewan as of mid-February, 1983. Part 3 discusses the principal features of the British Columbia marketing system and presents the Study Group's recommendations.

1.4 Units of Measurement

Discussion and illustrative calculations in this report are in terms of imperial units of measure, i.e. acres, thousand cubic feet (Mcf), billion cubic feet (Bcf) etc. This is for the convenience of those more familiar with such units than with S.I. units.

1.5 Abbreviations

The following abbreviations of names are used in this report:

Alberta and Southern Gas Co. Ltd.	A&S
Alberta Department of the Environment	Alberta Environment
Alberta Gas Ethylene Company Ltd., The	AGE
Alberta Gas Trunk Line Company Limited	AGTL
Alberta Natural Gas Company Ltd.	ANG
Alberta Petroleum Marketing Commission	APMC
Amoco Canada Petroleum Company Limited	Amoco
Attorney-General of the Province of British Columbia	AGBC
British Columbia Gas Corporation	BCGC
British Columbia Hydro and Power Authority	B.C. Hydro
British Columbia Petroleum Corporation	BCPC
British Columbia Utilities Commission	BCUC
BP Canada Inc.	BP

Canadian-Montana Gas Company, Ltd.	Canadian-Montana Gas
Canadian-Montana Pipe Line Company	Canadian-Montana Pipe Line
Canadian Petroleum Association	CPA
Canadian Utilities Limited	Canadian Utilities
Canadian Western Natural Gas Company Limited	Canadian Western
Columbia Natural Gas Limited	Columbia
Consolidated Natural Gas Limited	Consolidated Natural Gas
DataMetrics Limited	DataMetrics
Dome Petroleum Limited	Dome
Energy Resources Conservation Board of Alberta	ERCB
Esso Resources Canada Ltd.	Esso
Fort Nelson Gas Limited	Fort Nelson
ICG Utilities (British Columbia) Ltd.	ICG
Independent Petroleum Association of Canada	IPAC
Inland Natural Gas Co. Ltd.	Inland
KannGaz Producers Ltd.	KannGaz
Lloydminister Gas Company Limited, The	Lloydminster Gas

Many Islands Pipe Lines (Canada) Limited	Many Islands Pipe Lines (Canada)
Many Islands Pipe Lines Limited	Many Islands Pipe Lines
Ministry of Energy, Mines and Petroleum Resources of British Columbia	Ministry
Ministry of Energy and Natural Resources of Alberta	ENR
Montana Power Company, The	Montana Power
National Energy Board	NEB
Northland Utilities (B.C.) Ltd.	Northland
Northwest Pipeline Corporation	Northwest Pipeline
Northwestern Utilities Limited	Northwestern
NOVA, AN ALBERTA CORPORATION	NOVA
Ocelot Industries Ltd.	Ocelot
Pacific Northern Gas Ltd.	PNG
Pan-Alberta Gas Ltd.	Pan-Alberta
PanCanadian Petroleum Limited	PanCanadian
Petro-Canada	Petro-Canada
Petrofina Canada Inc.	Petrofina
ProGas Limited	ProGas
Public Utilities Board of Alberta	PUB

Saskatchewan Power Corporation	Sask Power
Sulpetro Limited	Sulpetro
Tennessee Gas Pipeline Company (Division of Tenneco Inc.)	Tennessee Gas Pipeline
Texas Eastern Transmission Corporation	Texas Eastern
TransCanada PipeLines Limited	TCPL
Trans Quebec & Maritimes Pipeline Inc.	TQ&M
Transcontinental Gas Pipe Line Corporation	Transco
Transwestern Pipeline Company	Transwestern
Westcoast Transmission Company (Alberta) Ltd.	Westcoast Alberta
Westcoast Transmission Company Limited	Westcoast

2 Highlights of the Present Systems of Developing and Marketing Natural Gas in British Columbia, Alberta and Saskatchewan

2.1 Disposition of Petroleum and Natural Gas Rights

2.1.1 Ownership of Petroleum and Natural Gas Rights

British Columbia Approximately 95 percent of petroleum and natural gas rights are owned by the province and are administered by the Petroleum Resources Division of the Ministry of Energy, Mines and Petroleum Resources under the provisions of the Petroleum and Natural Gas Act, RSBC 1979 c. 323.

Alberta Approximately 75 percent of all natural gas produced in Alberta is owned by the province and is administered by the Mineral Resources Division of the Ministry of Energy and Natural Resources under the provisions of the Mines and Minerals Act, RSA 1980 c. M-15.

Saskatchewan Approximately 85 percent of all natural gas rights are owned by the province and are administered by the Department of Energy and Mines under the provisions of the Mineral Resources Act, RSS 1977 c. M-16.

2.1.2 Disposition of Rights

In all three provinces companies may request the government to post lands for public bidding for exploration and development rights. Each province reserves the right to reject bids.

British Columbia Disposition of Crown reserve petroleum and natural gas rights is by sealed tender at one of the 5 to 7 dispositions held annually.

Disposition is normally by cash bonus bid but may also be in the form of a work obligation.

Applications for title in non-Crown reserve areas may be filed with the Commissioner of Petroleum Titles.

Tenure to explore, develop and produce petroleum and natural gas is granted by the issuance of a Permit, a Drilling Licence or a Lease.

(i) Permits (used, in general, for exploration in unexplored areas): A Permit may be issued for a term of 5 to 8 years over a minimum area of approximately 20,000 acres to a maximum area of approximately 121,000 acres and conveys the exclusive right to conduct exploratory drilling for Crown-owned petroleum and natural gas. Payment of an annual fee and rental, ranging from $0.20 to $1.01 per acre over an eight year period, is required. The permittee must satisfy annual dollar value work requirements during the term of the Permit. Upon expiry of a Permit, 50 percent of the Permit area may be converted to Leases.

(ii) Drilling Licence (used for exploration in an established area): A Drilling Licence may be issued for a term of 3 to 5 years based on geographic location, over a minimum area of approximately 640 acres to a maximum area of some 23,000 acres and conveys the exclusive right to conduct exploratory drilling for petroleum and natural gas. Payment of an annual rental of $1.01 per acre is required. Upon completion of an earning well or wells, the Licence may be terminated and converted to Leases. The area that may be converted to Lease depends on the number and depth of wells drilled.

(iii) Lease (used for exploration and development): A Lease can be acquired by direct application, by sale or by conversion of a Permit or Drilling Licence.

A Lease may be issued for a term of 5 to 10 years, depending on geographic location, over a minimum area of 160 acres to a maximum of some 5,800 acres and conveys the exclusive right to explore, drill, develop and produce petroleum and natural gas. Leases apply only to the base of the deepest formation penetrated. Payment of an annual rental of $3.04 per acre is required. A Lease, or that portion of a Lease, with proven underlying reserves may continue on a yearly basis after expiry of the Lease's initial term.

Alberta Disposition of petrolem and natural gas rights is by sealed tender at one of the dispositions held at two week intervals. Disposition is by cash bonus bid.

Tenure to explore, develop and produce petroleum and natural gas is granted by the issuance of a Petroleum and Natural Gas Licence or Lease.

(i) Petroleum and Natural Gas Licence (used for exploration): A Petroleum and Natural Gas Licence may be issued for a term of 2 to 5 years over maximum areas of 29 to 36 sections (18,560 to 23,040 acres) based on geographic location. The Licence conveys the right to drill for and produce petroleum and natural gas prior to making final Lease selection from the Licence. Upon completion of an earning well or wells, the Licence may be terminated and converted to Petroleum and Natural Gas Leases. The area that may be converted to Lease depends on the number and depth of wells drilled. Payment of an annual rental of $1.01 per acre is required.

(ii) Petroleum and Natural Gas Lease (used for exploration and development): A Petroleum and Natural Gas Lease conveys the right to explore, drill, develop and produce petroleum and natural gas within a specified area. The Lease can be obtained by converting a Petroleum and Natural Gas Licence or can be acquired at a sale.

If the latter, there are no restrictions. If selected from a Licence, the Lease may be issued for a term of 5 years over minimum areas of 3 to 8 sections (approximately 1,920 to 5,120 acres) and maximum areas of 29 to 36 sections (approximately 18,560 to 23,040 acres). Payment of an annual rental of $1.01 per acre is required. After expiry of the initial term, portions of the Lease with proven underlying reserves may be continued on a yearly basis.

Saskatchewan Disposition of petroleum and natural gas rights is by sealed tender at one of four dispositions held annually. Disposition is normally by cash bonus bid, but the government may consider net royalty bids although these are rare today.

Tenure to explore, develop and produce petroleum and natural gas is granted by the issuance of a Permit, Drilling Reservation or Lease.

(i) Permit (used for exploration): A Permit may be issued for a term of 3 years over a minimum area of 100,000 acres and conveys the right to explore for petroleum and natural gas. Payment of an annual rental of $0.10 per acre is required. The permittee must satisfy annual exploration expenditure requirements during the term of the Permit.

Upon expiry of a Permit, 40 to 70 percent of each Township[1] within the Permit area may be converted to Leases, based on the size of the Leases or the formation depth of a commercial discovery of petroleum or natural gas on the Permit area.

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1 A Township contains approximately 23,040 acres.

(ii) Drilling Reservation (used for exploration and development): A Drilling Reservation may be issued for a term of 1 year over a maximum area of 20,000 acres and conveys the right to explore for petroleum and natural gas. Payment of an annual rental of $0.50 per acre is required. The holder of a Drilling Reservation must commit to test a specific geological formation by drilling, thus earning up to 50 percent of the Drilling Reservation as Petroleum and Natural Gas Leases based on the depth of the formation tested. A discovery of natural gas in commercial quantities entitles the holder of the Drilling Reservation to select additional Leases in the discovery zone.

(iii) Lease (used for exploration, development and production): A Lease may be issued for a term of 5 years over a minimum area of approximately 160 acres and a maximum area of approximately 7,840 acres and conveys the right to explore, develop and produce petroleum and natural gas. Leases apply only to the base of the deepest formation penetrated by the first well. Payment of annual rental of $1.00 per acre[1] is required. After expiry of the initial term a Lease, or that portion of a Lease with proven underlying reserves, may continue on a yearly basis.

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[1] Reduced to $0.50 per acre where gas is discovered but markets for the gas are not available, and to $0.10 per acre where the lessee relinquishes his oil rights in the Lease.

2.2 Development of Natural Gas Supply

2.2.1 Exploration and Production

In all three provinces exploration for, and the production of, natural gas is done primarily by private sector producers who finance, drill and operate the wells.

British Columbia Some 150 exploratory and 62 development wells were drilled in British Columbia in 1981. Estimated numbers for 1982 are 65 and 45. Total marketable gas production in British Columbia during 1981 was 239 Bcf with some 225 Bcf estimated for 1982. The top 15 producers accounted for 80 percent of production. (See Appendix 4)

Alberta Some 883 exploratory and 2,173 development wells were drilled in Alberta in 1981. Estimated numbers for 1982 are 575 and 1,550. Total marketable gas production in Alberta during 1981 was 2.3 Tcf with some 2.5 Tcf estimated for 1982.

Saskatchewan Some 20 exploratory and 5 development wells were drilled in Saskatchewan in 1981. Estimated numbers for 1982 are 4 and 2. Total marketable gas production in Saskatchewan during 1981 was 38.3 Bcf with some 38.7 Bcf estimated for 1982. Sask Power produced 22 percent of Saskatchewan's total gas production.

2.2.2 Out of Province Supply

There are two suppliers of out of province gas to the British Columbia domestic market; A&S and Westcoast Alberta. Columbia purchases gas from A&S and Westcoast Alberta for its customers in southeastern British Columbia. Inland has an exchange arrangement with A&S whereby Inland purchases A&S gas during peak winter months and returns these volumes in summer months.

In addition, Westcoast purchases out of province gas from Alberta and the Northwest Territories for export to the United States. Westcoast is currently committed to take the following volumes of out of province gas:

Out of Province Suppliers	Minimum Annual Volume Obligation 72% load factor (Bcf)
Pan-Alberta	38.1
Westcoast Alberta	12.0
Amoco	10.0
TOTAL	60.1

2.2.3 Gathering, Processing and Transmission

The field gathering system includes the flowline system, the dehydration system and the field lateral which collects the raw gas from individual wells and transports it to a central point. The central point may be a processing plant or simply a point of connection with a transmission lateral.

Transmission laterals are pipelines which carry raw or marketable gas from the field gathering point or the processing plant to a main transmission line.

Raw gas refers to gas that may have been dehydrated but not otherwise processed and therefore, may contain significant quantities of natural gas liquids, hydrogen sulphide and carbon dioxide. Some of these liquids and the sulphur are removed at a processing plant.

Marketable gas transmission lines are the main, or trunk, pipelines which carry marketable gas from the processing facilities to the points where it is sold to utility companies or, in the case of Alberta and Saskatchewan, to large industrial users.

British Columbia In British Columbia, the producers build, own, and operate the field gathering system including the field lateral which connects to a raw gas transmission lateral. Every facility downstream of this connection point is built, owned and operated by Westcoast. The construction of facilities is undertaken by Westcoast after receiving a letter of request from the BCPC and approval by the NEB. Westcoast's return on these new facilities is guaranteed by the BCPC. The facilities include raw gas transmission laterals, raw gas transmission lines, processing plants and marketable gas transmission lines. If a pipeline is classified as a "regulated project", pursuant to the Utilities Commission Act, SBC 1980 c. 60, it also requires a provincial Energy Project Certificate.

The province's three processing plants are located at Fort Nelson, at Taylor and near Chetwynd. In addition to requiring NEB approval, these facilities are subject to British Columbia's environmental and safety regulations.

Alberta Producer's build, own and operate the facilities up to, and including, the processing plant. This includes the field gathering system, the raw gas transmission facilities (limited to short distance laterals extending from the dehydration plant to the processing plant), and the processing plants (owned and operated either singly or as a joint venture). The processing plants require permits from both the ERCB and Alberta Environment.

The facilities which carry marketable gas in Alberta (i.e. the transmission laterals and marketable gas transmission lines) are, in most cases, owned and operated by NOVA. All NOVA facilities require ERCB permits.

NOVA normally builds transmission laterals at the request of the producer. If NOVA considers the lateral to be uneconomic, it will charge the producer a surcharge to cover the incremental costs. In rare

cases, producers may build laterals but they are not encouraged to do so.

Some marketable gas transmission lines are owned and operated by the province's major utilities but these were constructed before the creation of NOVA, or its predecessor Alberta Gas Trunk Line Limited.

Saskatchewan While Sask Power may build field gathering systems, it normally allows producers to build these facilities. The producer incurs the capital and operating costs.

The field laterals connect directly with the processing plants. There are only three processing plants in Saskatchewan. The Steelman plant is owned and operated by Dome, the Smiley plant is owned and operated by Esso, and the Coleville plant is owned jointly by Dome and Sask Power and is operated by Dome. The plants are authorized by the Department of Energy and Mines.

Sask Power has the authority to build, own and operate all provincial transmission lines, excluding interprovincial trunklines such as TCPL.

2.2.4 Straddle Plants

Straddle plants are gas processing plants located downstream of the raw gas processing plant(s) and are designed to recover additional natural gas liquids from marketable natural gas. These plants have the effect of reducing the heating value of the marketable natural gas.

British Columbia There are no straddle plants in the province, although the government remains interested in ethane-based petrochemicals. A straddle plant would be required to locate on, or near, Westcoast's right-of-way. If the plant were owned by Westcoast the NEB would have control. Furthermore, NEB authorization for tapping the Westcoast mainline would

be required regardless of who owned the plant.

Alberta There are four straddle plants in Alberta: one near Edmonton, one at Cochrane and two at Empress. They are owned and operated respectively by Dome and Canadian Utilities, Alberta Natural Gas, Dome and PanCanadian and, PanCanadian and Petro-Canada. All of these plants recover ethane, propane and butane. Such plants require ERCB approval.

Saskatchewan There are no straddle plants in Saskatchewan.

2.2.5 Underground Storage

Underground storage of natural gas, as in a depleted gas pool or other suitable reservoir, may facilitate the delivery of natural gas to market by providing supplementary delivery capacity to meet peak loads.

British Columbia There are no storage facilities in operation in British Columbia. Several companies have investigated underground storage possibilities in the Lower Mainland near the largest market for natural gas. In addition, B.C. Hydro is currently conducting negotiations to access downstream storage facilities in the United States.

Existing gas reservoirs in the Fort St. John area are being investigated by the BCPC and Westcoast for storage potential. These projects have experienced regulatory problems related to facility operation and to the protection of the owner of the petroleum and natural gas rights.

Alberta Canadian Western owns two storage fields at Bow Island and Carbon although the former is depleted due to leakage and the latter is leased to TCPL. North Western is developing the salt caverns near Edmonton and expects to bring this storage facility onstream by 1984.

Saskatchewan The five storage fields in Saskatchewan are: East Cantuar; Bayhurst Unit; Unity Project; Pierceland and Beacon Hill. Sask Power owns all fields except for East Cantuar which is owned by Dome. Sask Power, however, owns the gas held in storage at East Cantuar.

2.2.6 Distribution

Distribution refers to the distribution of marketable gas, normally by a utility, to residential, commercial and industrial consumers.

British Columbia Six of the seven natural gas distribution utilities in British Columbia are investor-owned. B.C. Hydro, the largest, is a Crown Corporation. All utilities except Columbia purchase gas directly from Westcoast and all are regulated by the BCUC. The following table identifies the utilities, the areas which they serve and their 1981 sales.

Table 1
UTILITIES, AREA SERVICED AND SALES

Utility	Area Served	1981 Sales (Bcf)
B.C. Hydro	Lower Mainland	85
Inland	Okanagan, Central and Northern Interior,	52
Columbia	East Kootenays	
PNG	Summit Lake to Prince Rupert and Kitimat	12
Fort Nelson	Fort Nelson	
ICG	Fort St. John, Taylor Refinery	5
Northland	Dawson Creek, Tumbler Ridge	
Total		154

Alberta All gas utilities in Alberta are privately owned with the exception of that serving Medicine Hat which is owned by the City of Medicine Hat. Alberta's two major utilities are Northwestern and Canadian Western, serving Edmonton and Calgary respectively. In 1981, Northwestern's sales were 211 Bcf and Canadian Western's sales were 143 Bcf. The utilities are regulated by the PUB. Rural areas are served partly through the major utilities and extensively through cooperatives.

Saskatchewan Sask Power distributes gas within the province except in the City of Lloydminster which is served by a private utility, Lloydminster Gas. Sask Power's 1981 sales were 99 Bcf.

2.3 Marketing Arrangements

For convenience, those marketing arrangements or transactions which occur upstream of the marketable gas transmission lines are discussed under the heading 'upstream'. The subsequent, or downstream procedures, are discussed under the headings 'intraprovincial', 'interprovincial' and 'international'.

2.3.1 Upstream Procedures

British Columbia The first transaction is between the producer and the BCPC, which is the sole purchaser of gas from producers in British Columbia. The BCPC purchases raw gas from producers immediately downstream of the gathering point metering station where the gas enters the Westcoast raw gas transmission lateral. The BCPC then immediately resells all the gas to Westcoast in accordance with the BCPC/Westcoast agreement. This transaction is intended to secure provincial jurisdiction over natural gas and to facilitate the collection of the province's 'economic rent'.

Recoverable natural gas liquids and sulphur contained in the gas stream are the property of Westcoast. However, once any by-products are removed they become the property of the BCPC. The BCPC, acting on behalf of the province, administers the resale of all by-products.

Alberta The initial sale from the producer to the first purchaser is of marketable natural gas and normally takes place at the metering station downstream of the processing plant where the gas enters the NOVA system. The first purchaser may be a small cooperative, a distribution utility, a direct industrial user or an exporter. If the sale is to a small cooperative it is likely to be the last sale.

The second transaction is a purchase and sale through the APMC at the same point as the initial sale. The APMC purchases the gas from, and immediately resells it to, the first purchaser. This transaction is intended to secure provincial jurisdiction and to establish a basis for the distribution of revenue from export sales.

The producer owns the natural gas by-products which are removed at the field processing plant. Liquids removed in straddle plants located on NOVA's pipeline network are the property of the plant owner.

Saskatchewan Sask Power generally purchases gas from the producers; however, by arrangement, it allows Dome and Esso to purchase gas from producers in the vicinity of their processing plants. For gas which does not require processing, Sask Power purchases gas directly from producers at the wellhead or downstream of the compressor.

The second sale, for processed gas which is not owned by Sask Power, is downstream of the processing plant.

2.3.2 Intraprovincial

British Columbia Westcoast sells marketable gas to the various utilities in the province. Ordinarily the utility sells directly to the consumer. However, in the gas sale to Ocelot for its methanol plant at Kitimat, the utility (PNG) sells to the BCGC, a wholly owned subsidiary of the BCPC. The BCGC then sells the gas to Ocelot, the final consumer.

Alberta Except in the case of a cooperative buying for rural residents, utility companies distribute and sell gas to the residential, commercial and industrial markets. Additionally, a producer may sell directly to an industrial user.

A permit must be obtained from the ERCB before ethane can be removed from the province whereas there are no formal provincial restrictions on the removal of other natural gas by-products.

Saskatchewan Sask power sells to residential, commercial and industrial customers within the province with the exception of Lloydminster Gas customers as noted in Section 2.2.6.

2.3.3 Interprovincial

British Columbia No British Columbia gas is sold interprovincially, but transactions do occur in the reverse direction as discussed in Section 2.2.2.

Alberta Alberta is a major interprovincial supplier and rarely purchases out of province supplies. (In 1981, Alberta imported a very small amount of United States gas.) TCPL is the major interprovincial seller of natural gas produced in Alberta. Other interprovincial sellers include: A&S, Pan-Alberta, Westcoast Alberta and Many Islands Pipeline. These companies normally purchase gas from the producer at the metering station of the processing plant outlet where the gas enters the NOVA transmission lateral.

The final sale is by the interprovincial seller to a distributor outside Alberta.

Saskatchewan While Saskatchewan sells very little gas interprovincially, it is a major purchaser of Alberta gas with about 60 percent of its total domestic requirements coming from that province.

2.3.4 International

'International transactions' refers to present export sales to the United States, proposed

offshore LNG sales and natural gas by-product sales outside Canada.

British Columbia Westcoast sells British Columbia and out of province gas to Northwest Pipeline at the Huntingdon border point under NEB Licence GL-41. The NEB has also authorized the export of gas under Licence GL-41 by Westcoast at Monchy, Saskatchewan. Licence GL-41 authorizes the export of some 296 Bcf per year but actual exports have fallen short of this: 154, 134 and 92 Bcf in 1980, 1981 and 1982 respectively. The Westcoast/Northwest Pipeline contract contains no effective take-or-pay provisions; consequently Northwest Pipeline is using its Westcoast supply for peaking purposes.

Arrangements for providing gas to the proposed Dome LNG plant have yet to be made.

Alberta Among the many companies which export Alberta gas are: TCPL, Pan-Alberta, ProGas, A&S, Consolidated Natural Gas, Canadian-Montana and Sulpetro. Most of Alberta gas is exported at points east of Alberta or through Kingsgate, British Columbia. Only Canadian-Montana exports gas at the Alberta/United States border.

The sale of Alberta's natural gas by-products is subject to NEB regulation. NEB licenses are required for the export of ethane, propane, butane and pentanes-plus.

Saskatchewan At present there are no natural gas exports from Saskatchewan. However, Ocelot has applied to both the NEB and the provincial government to export Saskatchewan gas.

2.4 Pricing and Related Matters

As referenced in the preceding section, those pricing transactions which occur upstream of the marketable gas transmission lines are discussed under the heading 'upstream'. The downstream transactions are discussed under the headings 'intraprovincial', 'interprovincial' and 'international'.

2.4.1 Upstream

British Columbia The British Columbia 'upstream' natural gas pricing system is complex and involves a number of factors which are set periodically by government action.

Producers deliver raw gas to the BCPC and are paid a price based on the resulting processed gas volumes. This 'net field price' is royalty free and is set by Cabinet upon the recommendation of the BCUC. The details are given in the following formula:

$$NFP = BFP + NSS + FTR$$

where NFP = Net Field Price, in $ per Mcf
BFP = Base Field Price, in $ per Mcf, as set by Cabinet on the recommendation of the BCUC
NSS = Netback Stabilization Supplement, in $ per Mcf. This is a supplement to the base field price designed to offset the producer's varying liability for federal and provincial income tax with changes in the fair market value and the deemed field price.
FTR = Federal Tax Rebate, in $ per Mcf. This is a special rebate to compensate the producer for increased federal taxes resulting from the reduction in the excise tax on natural gas exports effective October 1, 1981 and the increase in the rate of Petroleum and Gas Revenue Tax (PGRT) since January 1, 1982.

The netback stabilization supplement is determined by the following formula:

$$NSS = TF\ (FMV - DFP)$$

where TF = Tax Factor, being the rate payable by a fully taxable producer for federal and provincial taxes.

FMV = The Fair Market Value of the gas within the meaning of Section 69(8) of the Income Tax Act, SC 1970-71-72 c. 63, in $ per Mcf. The producer is assessed for federal and provincial income tax on this amount.

DFP = Deemed Field Price is set by Cabinet, in $ per Mcf.

The fair market value is calculated monthly in accordance with Section 69(8) of the Income Tax Act as illustrated below:

$$FMV = \frac{(ESR + DSR + BPR) - (COS + OC)}{GP}$$

where ESR = Revenue from export gas sales, $

DSR = Revenue from domestic gas sales, $

BPR = Revenue from by-product sales, $

COS = Westcoast's cost of service, $

OC = BCPC's operating costs, $

GP = Total volume of processed gas produced, Mcf.

To illustrate the net field price calculation, the various factors for the month of November 1982 were as follows:

BFP = $1.67 per Mcf for new gas; $1.32 per Mcf for old gas

NSS = $-0.196 per Mcf

based on:

TF = 0.48
FMV = $2.141 per Mcf
DFP = $2.55 per Mcf

with FMV calculated from:

ESR = $40,130,000
DSR = $33,011,000
BPR = $ 3,313,000
COS = $22,738,000
OC = $ 125,000
GP = 25,033,000 Mcf

FTR = $0.23 per Mcf for new gas; $0.22 per Mcf for old price

from which:

NFP = ($1.67 + (-0.196) + 0.23) or $1.70 per Mcf for new gas;
= ($1.32 + (-0.196) + 0.22) or $1.34 per Mcf for old gas

Provided that the gas has at least 0.25 gallons of pentanes-plus per thousand cubic feet raw gas, the BCPC pays producers 12.5 percent of the average market price F.O.B the processing plant for all by-products. If the gas has less than 0.25 gallons of pentanes-plus per thousand cubic feet raw gas, the producers are not paid for any by-products. In these circumstances, the BCPC does not charge the producer for processing although it has the right to negotiate an equitable charge.

In 1981, the BCPC negotiated a reduction in its take-or-pay commitment to producers from 72 percent to 52 percent of its minimum annual volume obligation for the period 1981 to 1983 inclusive. The BCPC has no take-or-pay arrangement with Westcoast.

Alberta Producers in Alberta receive a gross field price upon which royalty is payable. A producer's average field price depends on the proportion of gas destined for consumption inside and outside Alberta as well as on his pro-rata share of the excess of export revenues over interprovincial revenues on equivalent volumes. This can be depicted as follows:

$$GFP = \frac{REV_1 + REV_2}{TMP} + \text{Price Adjustment}$$

where GFP = Gross Field Price, in $ per Mcf.

REV_1 = Revenue from Alberta gas destined for out-of-province consumption. The unit revenue is the Alberta border price less the purchaser's cost of service within Alberta, in $.

REV_2 = Revenue from gas destined for in-province consumption. The unit revenue is either the Alberta border price or a lower contract price, less the 'deemed' cost of service (see following explanation), in $.

Price Adjustment = The net amount that flows back to producers of eligible gas (i.e. the value of the exports less the international cost of service less the Alberta border price less the Market Development Incentive Program (MDIP) payments.) The MDIP payments are the product of incremental sales to new domestic markets east of Alberta and 30 percent of the Alberta border price.

TMP = Producer's total marketable production, Mcf.

The contract sales price is normally associated with a take-or-pay obligation of about 80 percent of the daily maximum volume obligation although A&S, Pan-Alberta and TCPL have negotiated lower take-or-pay commitments with the producers from 1980 on.

The deemed cost of service is a 'postage stamp' rate, uniform across the province, which is set by the APMC for gas sold intraprovincially to reflect the total cost of the movement of the gas from the contract delivery point to a point on the Alberta border. In its calculation, the APMC takes account of the actual average cost of service for interprovincial shippers plus other costs associated with the movement of the gas excluding interest on monies paid by purchasers under their take-or-pay contracts for gas not taken. As well, the APMC sets the cost of service separately for each purchaser of gas destined for outofprovince consumption. The purchaser's cost of service is based on administrative expenses, his return on rate base, his NOVA pipeline charge and his carrying charges on take-or-pay where applicable.

The price adjustment concept reflects a policy that all producers receive the same price for gas sold, other than their voluntary discount sales, irrespective of market.

In November 1982, the gross field price for a producer selling all his gas to TCPL for markets outside Alberta was:

Alberta Border Price	$2.32 per Mcf
Alberta Cost of Service	$0.46 per Mcf
Price Adjustment	$1.03 per Mcf
Gross Field Price	$2.89 per Mcf

In general, prices for ethane, propane, butanes, and sulphur sold in Canada are unregulated and thus determined by market forces. An exception is the ethane sold to the Alberta Gas Ethylene (AGE) plant - the only petrochemical plant in Alberta using ethane at present - which is priced on a cost of service basis, namely the energy equivalent of the field price of the natural gas plus the cost of service for extracting and pipelining. This is a private arrangement between the ethane producers and AGE. Pentanes-plus is priced according to the schedule for crude oil prices.

A minimum export price is set by the NEB for propane and butane sold internationally.

Saskatchewan Minimum field prices for Saskatchewan natural gas are set by the Minister of Energy and Mines. To date, prices have been set to yield what the government considers a 'fair' return to producers, where the government's determination of a fair return has been made without explicit reference to returns earned in other jurisdictions such as Alberta or British Columbia. While these are the minimum prices Sask Power must pay producers for marketable gas, the utility is free to pay more if it feels higher prices are warranted. Producers may also apply directly to the government for higher prices, but higher prices are normally granted only in cases of exceptionally high operating costs.

The present natural gas price formulae, which distinguish between 'new', 'old' and 'solution' categories, are provided below:

New Gas

Daily Well Production (DWP) (Mcf)	Recommended Minimum Price ($ per Mcf)
Less than 106	1.06
106 to 459	$\text{Price} = \frac{DWP^2 - 918\ DWP + 41816}{313308}$
Greater than 459	0.66

Old Gas

Old Gas Price = 0.57 x New Gas Price (at the same DWP)

Solution Gas

Solution Gas Price = The maximum of the highest New Gas Price or $1.06 per Mcf.

In Saskatchewan 'old' gas is defined as gas from a well that commenced production before October 1, 1976, while 'new' gas is gas from a well that commenced production after that date.

These prices are for marketable gas delivered to a single point in a gas field. If Sask Power has to gather the gas, producers are charged a gathering fee calculated on a cost of service basis. When the gas is processed by a third party, either the processor or producer may gather the gas.

Arrangements for processing gas are fairly flexible. For example, processors may purchase gas from other producers and sell the processed gas to Sask Power at the recommended price.

2.4.2 Intraprovincial

British Columbia Westcoast sells gas to the intraprovincial utilities at a wholesale price set for each utility by Cabinet upon the recommendation of the BCUC. This wholesale price is fixed independently of the net field price or the deemed fair market value. The major contracts between Westcoast and the utilities contain take-or-pay clauses. In December 1982 the average wholesale prices for the three largest utilities were:

Utility	Price $ per Mcf
B.C. Hydro	2.02
Inland	1.65
PNG	1.58

Normally, a utility sells to the final consumer at the wholesale price plus its cost of service as set by the BCUC. However, in the gas sale to the Ocelot methanol plant at Kitimat, PNG sells the gas to the BCGC at its regulated industrial price. Then the

BCGC sells to Ocelot at the price negotiated between Ocelot and the BCPC.

Alberta A cooperative may buy small volumes of gas directly from the producers and sell to its rural customers at a price covering its purchase cost plus its cost of service less the provincial government rebate. The rebate is equal to the difference between the price paid to producers for the gas and the support price (i.e. 65 percent of the Alberta border price).

Similarly, a utility sells gas at its purchase cost plus the applicable NOVA cost of service plus its own distribution cost of service less the provincial government rebate.

Saskatchewan Sask Power sells the gas which it purchases from the producer directly to the consumer. The consumer price is determined by a formula and is discussed in detail in Section 2.14.

2.4.3 Interprovincial

British Columbia Inland buys A&S gas at the Alberta border price plus transportation costs plus 30 percent of the price A&S pays the producer. Within six months, Inland sells the gas back to A&S at the Alberta border price.

Columbia purchases gas from A&S at the Alberta border price plus transportation costs.

The price which Westcoast pays for Alberta and Territories gas destined for export is the Canada/United States border price less the portion of Westcoast's cost of service allocated to it. For Alberta gas this amounts to transmission alone. For the Territories gas, which is processed in British Columbia by Westcoast, this amounts to processing and transmission costs.

Alberta The net field price for gas sold interprovincially is the Alberta border price less the purchaser's cost of service as set by the APMC. Therefore, a producer may receive several different field prices for gas destined for out of province consumption, if it is sold to several purchasers each with different costs of service.

Saskatchewan Sask Power purchased some 60 Bcf of Alberta gas in 1981 at the Alberta border price plus transportation cost.

To protect Saskatchewan's future natural gas requirements, Sask Power has arranged a number of long term contracts (generally for 20 years) with TCPL for Alberta supplies and with individual Saskatchewan producers for Saskatchewan supplies. In addition, Many Islands Pipeline, a wholly owned subsidiary of Sask Power, produces and purchases Alberta natural gas for consumption in Saskatchewan.

In the past, Sask Power has generally committed to take-or-pay for more than 80 percent of contracted volumes. However, because of recent marketing problems it is attempting to reduce its take-or-pay obligations to no more than 75 percent of contracted volumes on new contracts and renewals of old contracts.

The gas which is sold to eastern Canada from the Steelman plant receives the Toronto city gate price less TCPL tolls.

2.4.4 International

The federal government sets the international border price for all natural gas exports to the United States. This price is currently $4.94 U.S. per MMBTU and is uniform for all sales of Canadian gas to United States markets regardless of load factor, market competition or Canada/United States border point.

British Columbia Under the Westcoast/Northwest contract, Northwest's current take-or-pay liability is in the form of a minimum annual bill calculated at 105 percent of the B.C. Hydro domestic price. Although the minimum bill increases as Hydro's price increases, Northwest Pipeline's purchase obligation corresponds to a very low take-or-pay obligation. For example, in 1982, the minimum annual bill would have been triggered by export volumes below 82 Bcf (i.e. 29 percent take-or-pay).

Alberta The exporter purchases gas from the producer at the same price as gas destined for interprovincial sales. The APMC then purchases the gas from the exporter at the exporter's purchase price and sells it back to him at the international border price netted back to the original point of sale (i.e. less the international cost of service and the purchaser's Alberta cost of service).

Finally, the exporter sells the gas to the United States customer at the international border price.

Saskatchewan There are no exports of Saskatchewan gas at the present time.

2.4.5 Transmission Tariffs

British Columbia The NEB sets Westcoast's total cost of service for its facilities including a return on its rate base. The NEB also allocates Westcoast's total cost of service between British Columbia gas and the Alberta and Territories gas deemed for export. The province, through the BCUC, then allocates the British Columbia gas cost of service among the domestic utilities.

Alberta NOVA sets its own transmission tariff, however a tariff increase may be rolled back for twelve months after a review by the PUB. The PUB will only review a tariff increase if it is appealed.

NOVA's tariff to any point on the Alberta border is a fixed 'postage stamp' rate. For transportation within the province, tariffs are set on a cost of service basis with the postage stamp rate as a maximum.

Saskatchewan Sask Power recovers the cost of transmission in its consumer price.

2.5 Market Development

2.5.1 Initiatives of Provincial Governments and Crown Corporations

British Columbia While there are no specific statutory requirements for market development, the Ministries of Energy, Mines and Petroleum Resources and of Universities, Science and Communications have made budget appropriations for the purpose of stimulating natural gas markets.

The Ministry of Energy, Mines and Petroleum Resources has taken such intiatives as: inviting and evaluating applications for gas projects including gas exports under the Natural Gas Allocation Process (NGAP); assessing the viability of providing natural gas service to Vancouver Island; and coordinating and administering a $1.5 million provincial program to extend gas service in the north and south Peace River regions. British Columbia's Gas Extension Program (GEAP) is being undertaken in cooperation with the federal Distribution System Expansion Program (DSEP).

The Ministry of Universities, Science and Communications has contributed to new market development by offering a $200 grant for private (individual) vehicle conversion to CNG (this is funded by the Energy Development Agency). The government also eliminated the fuel tax on CNG and propane to encourage substitution of these fuels for gasoline. Additional provincial commitments for the fiscal year 1983 include $125,000 for mechanics training in conversions at Pacific Vocational Institute in Vancouver, plus $180,000 for promotion of conversions.

The province, together with the BCPC, has taken an active role before the NEB, and in certain instances before U.S. federal tribunals, to promote and protect British Columbia gas exports. In addition, the BCPC is continuing its discussions with prospective purchasers and marketers.

Alberta One of Alberta's gas marketing initiatives stems directly from the September 1981 federal/Alberta agreement related to the National Energy Program (NEP). Under the Agreement, the APMC makes payments through a Market Development Incentive Program (MDIP) to the federal government to encourage the expansion of Alberta's gas markets in provinces east of Alberta. This incentive payment is the product of 30 percent of the Alberta border price and the quantity of gas sold to new domestic markets east of Alberta. The MDIP payments come out of the export flowback fund and, therefore, are revenue which would have otherwise gone to producers and the province.

Within the province, Alberta administers and funds its own rural gasification program. The province assists cooperatives in rural areas in providing gas to their members by offering a grant, based on the average extension cost above $1,700 per customer. In addition, the government of Alberta has made two statements (one in April 1982 and another in September 1982) regarding expanded export sales of natural gas.

Saskatchewan Sask Power is in the process of expanding its distribution facilities in the province to provide service to new areas. The provincial government has allocated $20 million for gas expansion in 1982/83 and has started five demonstration projects for rural gas expansion. In addition, the Saskatchewan government is currently reviewing its gas export policy with a view to finding markets in the United States.

2.5.2 Initiatives of the Federal Government and the NEB

Under the NEP, the federal government introduced several incentive programs designed to stimulate new markets for natural gas. The two programs which are applied consistently in all provinces are: the Canadian Oil Substitution Program (COSP) grant, which covers 50 percent of the cost (up to a specified

maximum) of converting residential, commercial and industrial heating requirements from oil to gas; and the $600 grant for commercial, fleet or private vehicle conversions to CNG.

With respect to exports, the NEP endorses the granting of export licences when a surplus is found to exist. Decisions to be taken by the federal government as a result of the recently concluded NEB Omnibus Gas Export Hearings will set the stage for additional Canadian gas exports in the future.

British Columbia The federal government has allocated $6.5 million of the 1982/83 federal DSEP funds to British Columbia to finance 58 gas extension projects. British Columbia is the only province where DSEP is funded by federal revenue not collected through Alberta's MDIP payments.

Another federal 'intiative' is the NEB's decision to initiate a review to require Westcoast to "show cause" why Licence GL-41 volumes should not be reduced if the take-or-pay commitment negotiated between Westcoast and Northwest is not brought into effect by July 1, 1983.

Alberta The federal DSEP program is opening up new markets for Alberta gas east of the Alberta border. NEB approval of the TQ&M pipeline and the $500 million 'laterals fund', established by the federal government to pay for construction of TQ&M laterals up to their current estimated cost, assures the distribution of Alberta gas in Quebec and possibly the Maritimes. An additional incentive which will stimulate Alberta gas sales is the new federal program, introduced November 1, 1982, whereby gas distributors in Quebec and the Maritimes receive a limited holiday from certain transmission charges until gas volumes are sufficient to utilize more completely the initial capital facilities. This program is also funded through Alberta's MDIP payments.

Saskatchewan Under DSEP, a total of $3.9 million has been allocated to Saskatchewan to finance 15 gas extension projects.

2.5.2 Producer Initiatives

British Columbia Dome is pursuing a new LNG market for British Columbia gas in Japan. A number of other producers have initiated efforts to develop specific sales but these have not progressed, partly because producers do not receive a direct benefit by selling gas to other than the BCPC.

Alberta Producers have the right to negotiate sales and are active both individually and in groups. Dome is also pursuing a new LNG market for Alberta gas in Japan.

Sulpetro has submitted a new application to the NEB to export gas to TRANSCO starting in 1983 for 8 years. The United States Energy Regulatory Agency has approved this import but approval has yet to be given by the Federal Energy Regulatory Commission.

Canadian Montana Gas and Canadian Montana Pipeline Company, wholly owned subsidiaries of Montana Power Corporation, have developed the Montana market.

ProGas, a limited company with about a dozen private shareholders (most of which are gas producers), markets gas in the United States. ProGas has applied to extend the term of its existing export licence and to export gas under a new licence to Texas Eastern, Transwestern and Texas Gas Transmission.

KannGaz, another limited company of some 49 Canadian independent oil and gas exploration companies, markets its own gas exclusively. The company has contracted to supply its gas to Tennessee Gas for the period 1983 to 1998 and has made application to the NEB for this export sale.

Pan-Alberta buys gas from 450 different producers for Canadian and export markets. Pan-Alberta's major thrust is through the Alaska Natural Gas Transmission System prebuild, both eastern and western legs.

Saskatchewan Ocelot has applied to the NEB and Saskatchewan government to export Saskatchewan gas starting on, or before, November 1, 1985, for a 16 year period.

2.5.4 Transmission Company Initiatives

British Columbia Westcoast has made applications to the NEB to extend Licence GL-41 and to sell gas to Tennessee Gas Transmission at Monchy, Saskatchewan. In the past, Westcoast has worked with Northwest Pipeline and other United States interstate pipeline companies to find markets for Canadian gas. Furthermore, Westcoast has participated in a number of United States regulatory proceedings in order to protect and increase Canadian gas markets serviced through the Westcoast system.

Alberta TCPL has been very active in marketing natural gas in Canada and the United States. In the recently concluded NEB Omnibus Gas Export Hearings, TCPL presented applications for exports in excess of 4 Tcf, excluding its additional supply request of more than 2 Bcf for the Dome LNG project.

A&S and Canadian-Montana Pipeline also presented applications at the Hearing for exports of 1.9 Tcf and .5 Tcf respectivley.

Saskatchewan The Study Group is unaware of any transmission company initiatives in Saskatchewan.

2.6 Royalties or Equivalent

Most of the gas produced in the three provinces is Crown-owned and is therefore subject to a Crown royalty or equivalent 'economic rent'. Each province has some gas which is owned by persons other than the Crown, and which is subject to both a freehold royalty and a freehold mineral tax.

2.6.1 Crown Royalties

British Columbia Natural gas that is sold to the BCPC is under a contract which stipulates that the BCPC undertakes to pay and satisfy all royalties levied by the province. Royalty regulations under the Petroleum and Natural Gas Act provide for a sliding scale royalty on Crown gas not sold to the BCPC. There is no gas, however, that is currently in this category, presumably because the royalty would lead to a much lower producer netback than may be received through sale to the BCPC.

Crown revenue is collected by the BCPC through the revenue from the sale of natural gas to Westcoast and from sales of the gas by-products less its gas purchase cost at the net field price (defined in Section 2.4). The BCPC remits the difference - the implicit royalty - to the government. The net field price is dependent on whether the gas is 'old', which is gas from pools on production before November 14, 1973, or 'new', which is all other gas.

The implicit royalty is equal to the difference between the deemed fair market value and the net field price. The equivalent royalty percent is:

$$R\% = \frac{(FMV - NFP)}{FMV} 100$$

The royalty in British Columbia would be negative if the fair market value were less than the net field price. In fact in some months, because of the

low domestic wholesale price and the low export sales volumes, the revenue received from Westcoast has been so low that the royalties have been negative; the BCPC has actually paid more to producers than it has received from Westcoast and from by-product sales. This, perhaps more than anything else, demonstrates the inadequacy of the British Columbia royalty system.

Substituting in this equivalent royalty formula the expressions given in Section 2.4.1 for net field price (NFP) and netback stabilization supplement (NSS), the equivalent royalty percent may be expressed as:

$$R\% = \frac{(FMV - BFP - NSS - FTR)}{FMV} 100$$

$$= \frac{((1 - TF)\ FMV + TF\ (DFP) - BFP - FTR)}{FMV} 100$$

With TF taken as 0.48, this becomes:

$$R\% = \frac{(0.52\ FMV + 0.48\ DFP - BFP - FTR)}{FMV} 100$$

and demonstrates that the equivalent royalty percent depends upon the fair market value (FMV), reflecting the actual value of the gas as it changes from time to time, and the deemed field price (DFP), base field price (BFP) and federal tax rebate(FTR) factors as set periodically by Cabinet using the current numerical value for these factors, which are as follows:

BFP = $1.32 for old gas; $1.67 for new gas
DFP = $2.55 per Mcf
FTR = $0.22 for old gas; $0.23 for new gas

The formulae can be expressed in a manner corresponding to the Alberta royalty as follows:

$$R\%\ old = \frac{-5.6 + 52(FMV - .50)}{FMV}$$

$$R\%\ new = \frac{-41.6 + 52(FMV - .50)}{FMV}$$

where R% old = Royalty Percent for old gas
R% new = Royalty Percent for new gas

Alberta The province levies an explicit sliding scale royalty on Crown-owned natural gas. This royalty system, which has been in effect since the early 1970's, involves a royalty rate dependent on the price, the vintage ('old' gas being defined as gas discovered before January 1, 1974 or 'new' defined as all other gas), and the production rate. The royalty is applied to the revenue from the sale of marketable gas, and may be taken in cash or in kind. Where the gas must be processed before sale, the province allows a processing allowance which is deductible from sales revenue before the royalty is applied. As well, a separate royalty is levied on natural gas liquids and sulphur.

Within this royalty system, Alberta has altered the royalty rate several times. The present royalty rates have been in effect since April 1, 1982. For gas sold at a price less than $0.50 per Mcf, the royalty rate is 22 percent. For gas sold at a price higher than $0.50 per Mcf, the royalty percent is determined by the formulae:

$$R\%\ old = \frac{11 + 45\ (GFP - .50)}{GFP}$$

$$R\%\ new = \frac{11 + 35\ (GFP - .50)}{GFP}$$

where R% old = Royalty Percent for old gas
R% new = Royalty Percent for new gas
GFP = Gross Field Price

If a gas well produces less than 597 Mcf per day, whether old or new gas, it qualifies for a reduced royalty rate determined by the formula:

$$R\%\ red = R\%\ norm - \frac{(R\%\ norm - 5)\ (597 - P)^2}{(597)^2}$$

where R% red = Reduced royalty percent
R% norm = Normal royalty percent for either old or new gas as in above formulae
P = Production rate, Mcf per day

A producer's actual total royalty payable on gas and gas by-products is based on the total revenue from natural gas and any by-products, less a reduced 'gas processing allowance' and is determined by the Department of Energy and Natural Resources, i.e.:

$$ARP = \frac{(ARR)(TR - GPA)}{100}$$

where ARP = Actual Royalties Payable, $
ARR = Average Percent Royalty Rate on gas and gas by-products
TR = Total Revenue from natural gas and gas by-product sales, $
GPA = applicable Gas Processing Allowance, $

Saskatchewan The province currently levies a uniform royalty of approximately $0.02 per Mcf on non-associated gas, while no royalty is levied on associated gas. (Non-associated gas is defined as gas produced from a well which produces more than 20 Mcf of gas to every barrel of oil.) While this royalty appears extremely low, the total economic rent received from producers of Saskatchewan natural gas is the sum of this small royalty plus the difference between what might be considered a fair market value for the gas in the field and the much lower government-fixed gross field price. The latter portion of the economic rent flows directly to the benefit of the Saskatchewan consumers.

Saskatchewan does not collect a royalty on natural gas by-products.

The Saskatchewan government is considering a new system with higher royalties and higher field prices for natural gas.

2.6.2 Freehold Royalties

In all three provinces a mineral rights holder other than the Crown has the right to negotiate a contract for royalty payments from the producer. These royalties, unlike Crown royalties, are deductible from production revenue in calculating federal taxable income and the PGRT. Freehold gas accounts for some 15 percent of Alberta's total production, whereas in British Columbia only a small amount of gas production falls into this category.

2.6.3 Freehold Mineral Tax

British Columbia The province levies a tax of $2.00 per acre on production tracts of freehold natural gas. Few producing wells are in this category and the total revenue to the Crown is relatively insignificant.

Alberta The province levies a freehold mineral tax based on the 'fair actual value' of petroleum rights, and a mill rate. The fair actual value is determined by the ERCB and is based on a forecast of the future revenues and costs over the remaining life of the reserves. The mill rate has remained unchanged since 1973 at 16 mills. Such taxes on natural gas production in 1981 totalled $75 million corresponding with an allocated share to freehold natural gas production of some $0.10 per Mcf.

Saskatchewan There is no freehold mineral tax on gas.

2.7 Provincial Taxes

2.7.1 Provincial Corporate Income Taxes

British Columbia Provincial corporate income tax is levied against taxable income as defined under the federal Income Tax Act, as amended, at a rate of 16 percent. A tax rebate is provided to account for provincial revenue collections. The rebate is equal to 16 percent of the difference between the deemed fair market value less the resource allowance and the net field price. The federal government collects a corporate income tax on behalf of the province. If a producer chooses to sell gas under the existing royalty system the royalty paid by the producer is an allowable deduction for calculating provincial corporate income tax.

Alberta Alberta applies its corporate tax at a rate of 11 percent on gross wellhead revenues less allowable expenses. Unlike British Columbia and Saskatchewan, Alberta collects its own corporate income tax and therefore has the ability to define the tax base. To date, Alberta has not deviated from the federal tax base. Alberta provides a tax rebate of 11 percent of the difference between royalties paid and the resource allowance. This rebate effectively makes royalties deductible for provincial income tax purposes.

Saskatchewan The province levies taxes against taxable income defined under the federal Income Tax Act at a rate of 14 percent, or at a rate of 11 percent for those companies qualifying for the federal small business deduction. Saskatchewan provides a rebate which effectively makes royalties deductible for provincial income tax purposes. The federal government collects Saskatchewan's corporate income taxes on behalf of the province.

2.7.3 Municipal Taxes

British Columbia Investor-owned utilities pay 1 percent of the gross revenues earned in a particular municipality in lieu of property taxes on distribution facilities. B.C. Hydro, as a Crown-owned utility, pays grants to the municipalities it serves in lieu of these taxes. As well, the investor-owned utilities are required to pay property taxes to the province based on the assessed value of their facilities. The assessed value of pipelines is set in regulations and varies only with the size of the pipe. For example, the assessment for a 12 to 14 inch pipeline is $139,200 per mile and the applicable tax rate is 1.2 percent. The total provincial revenue from such taxes in 1981 was $36 million (gas and oil pipelines).

Alberta Incorporated areas levy municipal franchise taxes in lieu of property taxes on distribution facilities. The actual tax varies across the province from a low of 1.5 percent of a utility's gross energy revenue to a high of 11.11 percent in Calgary and Edmonton. The total revenue from such taxes in 1981 was some $42 million.

Saskatchewan Sask Power pays a grant in lieu of property taxes on distribution facilities. The grant is financed through a 3 percent surcharge on consumer's accounts in towns and 5 percent in cities. The grants totalled $5 million in 1981.

2.7.3 Sales Tax

British Columbia Pursuant to the Social Services Tax Act, RSBC 1979 c.388, a sales tax is paid on oil field equipment brought into British Columbia and on consumables. The rate is 6 percent with a 50 percent rebate on equipment used for exploration operations.

Alberta There is no sales tax in Alberta.

Saskatchewan The province levies a 5 percent tax on consumables while capital equipment is exempt.

2.7.4 Special Levies

There are no special levies in British Columbia and Saskatchewan.

Alberta The ERCB levies a tax on all oil and gas properties. This is set to cover 50 percent of its oil and gas related expenses. In 1981, this tax totalled approximately $13 million.

2.8 Federal Taxes

2.8.1 Petroleum and Gas Revenue Tax (PGRT)

The federal government currently levies a PGRT on all oil and gas production in Canada. The basic PGRT rate was reduced from 16 to 14.67 percent for the period June 1, 1982 to May 31, 1983. The tax is calculated as 14.67 percent of net production revenues (i.e. gross revenues less field operating cost, field overhead costs and any overriding royalties) less a resource allowance of 25 percent of net production revenues. Small producers are eligible for an annual credit of up to $250,000 to be applied against the producer's PGRT liability for that year.

2.8.2 Corporate Income Tax - Producers

Producers pay tax at a rate of 36 percent on taxable income, with a surtax of 5 percent in 1982 (i.e. 5 percent of 36 percent). Allowable deductions are the same in all provinces. Investment tax credits (ITC) are deductible from federal tax liabilities. The ITC rate is 10 percent in British Columbia's major producing areas, 7 percent in Alberta's major producing areas and 10 percent throughout Saskatchewan. Under the NEP, depletion allowances have been eliminated for development expenditures and are rapidly being phased out for exploration expenditures on provincial lands.

Grants under the Petroleum Incentive Program (PIP) were intended to replace depletion allowances. These grants are discussed in Section 2.11.

2.8.3 Corporate Income Tax - Investor-Owned Gas Utilities

Investor-owned utilities pay the usual federal corporate taxes but the federal government rebates

95 percent of these taxes to the provinces. Alberta refunds the rebate to the utility, while British Columbia does not. Saskatchewan has no investor-owned utilities.

2.8.4 Natural Gas and Gas Liquids Tax (NGGLT)

The NGGLT was introduced under the NEP and is applied at the wholesale level on domestic sales. It is the federal government's stated intention to set the NGGLT so that the Toronto city gate gas price after the NGGLT is 65 percent, on an energy equivalent basis, of the Toronto refinery gate price of crude oil. Currently, the tax is $0.66 per MMBTU. Effective October 1, 1981, the federal government reduced the NGGLT to a zero rate on natural gas exports. The zero rate will remain in effect until December 31, 1986.

2.8.5 Canadian Ownership Special Charge (COSC)

The COSC, introduced to finance the purchase of Petrofina by Petro-Canada, is a $0.15 per MMBTU charge levied on all oil and gas consumption in Canada. This special charge is currently scheduled to be eliminated in March 1983, but may be continued to cover the cost of refinancing Dome.

The Toronto city gate price of gas inclusive of the NGGLT and the COSC (December 1982) is 68 percent of the Toronto crude oil price.

2.9 Difference in Producer Costs

The daily or footage rate charged by drilling contractors for drilling comparable wells in British Columbia and other provinces is not significantly different. However, there are several items of cost which are higher in British Columbia and cause overall drilling operations to be more expensive in this province. These are mainly in the following areas.

2.9.1 Workers Compensation Costs

Workers compensation costs are calculated on a different basis in each province and are less in British Columbia by reason of a lower payroll ceiling (the upper limit at which deductions are made) of $24,700 per year. (In Alberta and Saskatchewan the payroll ceiling is set at $44,000 per year.) However, British Columbia has a mandatory requirement of a first aid attendant, ambulance and first aid trailer at each drill site adding some $250 to $275 per day to drilling costs. The net effect is an additional cost of at least $5,000 per well in British Columbia.

2.9.2 Social Service Tax

The Social Service Tax Act in British Columbia (see Section 2.7.3) has the effect of increasing costs of exploration and production and, in certain instances, creating bookkeeping problems and added expense for drilling and service companies. For example, an engine sent in from Alberta to replace one returned for servicing is subject to taxes; or a fleet of pumping trucks sent in for a large fracture job is subject to this cost on all vehicles for a one-time operation.

2.9.3 Drill Sites and Access

Earth moving and other costs involved in the preparation of drilling sites and access roads are estimated to be 8 to 12 percent higher in British Columbia than in Alberta. Contributing to this difference are higher labour, equipment rental, fuel and commercial vehicle licence costs in British Columbia.

2.9.4 Fuel for Drilling Operations

Diesel fuel and gasoline is a significant cost item when drilling wells. These fuels are $0.05 cents per litre more expensive in British Columbia than in Alberta.

2.9.5 Drilling Time

Due to the smaller scale of drilling operations in British Columbia than in Alberta, certain services must be obtained from locations further from the drill site. This increases the average drilling time of a well in British Columbia (i.e. 25 days) by an estimated half-day.

2.9.6 Total Well Cost

A broad analysis to compare the total cost of a well drilled in British Columbia with a similar well drilled in Alberta indicates that the cost of the well in British Columbia is about 8 percent higher. This figure is made up of various cost items as shown in Table 2. The first column of this table shows the amount or percentage that the items represent of the total well cost and the second column shows the percentage (where applicable) by which the cost of these items in British Columbia is higher than in Alberta. The product of these two values is the contributing percentage to the difference in total well cost as shown in the third column.

Table 2

COMPARISON OF TOTAL WELL COSTS IN BRITISH COLUMBIA AND ALBERTA

Cost Item	% Total Well Cost	% Difference in Cost (BC vs Alta)	% Difference per well (BC vs Alta)
Misc. (W.C.B etc.)	($7,000 per $1 million well)		0.7
Sales Tax on Rig	($10,000 per $1 million well)		1.0
Sales Tax on Consumables	20	6	1.2
Drill Sites and Access	15	10	1.5
Fuel for Rig	10	15	1.5
Rig Contract Rate	--	0	0
Drilling Time	(1/2 day in a 25 day well)		2.0
Total			7.9%

While the comparable position in Saskatchewan was not examined, it is expected that the difference in cost between similar wells in British Columbia and Saskatchewan will be of the same order as discussed above. Also, it may be assumed that monthly operating costs of producing wells will be similarly higher in British Columbia than in Alberta and Saskatchewan.

2.10 Provincial Producer Incentives

2.10.1 Exploratory Drilling Incentives

British Columbia While oil producers in British Columbia receive a one year royalty holiday on oil produced from new pools, there is no such incentive for gas producers. However, there is a 50 percent rebate on the provincial sales tax on drilling equipment used for exploratory wells. Another incentive is provincially funded and constructed access roads. To date only one such access road has been built - the $3 million road from Clarke Lake to Sierra in north eastern British Columbia. The province maintains this road at a cost of $200,000 per annum.

Alberta The exploratory drilling incentives in Alberta take two forms.

The first is an exemption from royalty, or freehold mineral tax, for the initial production from a discovery well which earned exploratory drilling credits. Gas production from an incentive exploratory well[1], which started drilling between April 1981 and April 1982, is exempt for each of the first twelve months in which gas is produced. For certified wells which start drilling between April 1982 and January 1983 the royalty holiday lasts for 36 months and for wells which start drilling between January 1983 and April 1983, for 24 months.

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1 A well qualifies as an 'incentive exploratory well' if it is intended to be drilled deeper than 600 metres and is more than 4.8 kilometres from an existing well which has penetrated crude oil or gas deposits.

The second incentive is a credit given for each foot of qualified drilling in the province. The credit is recoverable as an offset against Alberta gas royalties, freehold mineral tax and land payments. The amount of this incentive is dependent on the depth of the well, its location within the province and its distance from earlier drilling. The well must qualify as an incentive exploratory well before it can earn any credits.

Saskatchewan The certified exploratory well[1] incentive is a grant which is dependent on incurring certain qualified costs. The grant is computed for each certified exploratory well as follows:

$$G = (\$5400 + 1.82D + 0.00115D^2)$$

where G = Grant
D = total well depth in feet

The inclusion of the depth factor is intended to encourage deeper and more exhaustive drilling.

Saskatchewan also has 'approved expenditure grants' relating to general research on conservation, development and production; well testing and exploration and development activities other than drilling; and the drilling and testing of wells other than qualifying exploratory wells (i.e. wells located on road allowances). An approved expenditure 'credit bank' is built up at a rate of 75 percent of approved expenditures, or by a formula which relates the grants to well depth. Disbursement of grants from the credit bank is dependent on production.

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[1] For certification, a well must meet three conditions that relate to distance from other wells. The government reserves the right to refuse certification or to impose conditions on certification.

2.10.2 Geophysical Incentives

British Columbia does not offer development drilling and well servicing incentives.

Alberta The well services incentive scheme was initially introduced as part of the provincial government's 1982 Oil and Gas Activity Program and involves payments of 50 percent of the cost of maintenance, repair and service work on oil and gas injection, water disposal and observation wells up to a limit of $75,000 per well. To qualify for this program, work must be completed by December 31, 1982.

Effective August 15, 1982, the program was extended to include cash grants covering approximately 25 percent of drilling costs for development wells on, or adjacent to, Crown land. This program also expires on December 31, 1982.

The total funds allocated under these two programs will not exceed $250 million. The $235 million ceiling for drilling incentives has been reached and no new applications are being accepted. The remaining $15 million was set aside for well servicing grants.

Saskatchewan Geographical incentives are offered through the approved expenditure grants program discussed in Section 2.10.1.

2.10.4 Petroleum Incentive Program

The Petroleum Incentive Program (PIP) in British Columbia and Saskatchewan is administered and funded by the federal government. (For a detailed discussion of PIP, see Section 2.11.1.)

Alberta Although federally initiated, the PIP in Alberta (APIP) is both administered and funded by the provincial government in accordance with the federal/Alberta agreement. At that time the Alberta

government estimated total payments under the program at some $4.3 billion over the term of the agreement (1981-1986).

2.11 Federal Producer Incentives

2.11.1 Petroleum Incentives Program (PIP)

The PIP applies to both provincial and federal lands and involves cash payments, calculated as a percentage of approved or eligible exploration and development costs, to qualified applicants. The actual percentage of cost given as a grant depends on: whether the activity is carried out on provincial or Canada lands; the Canadian ownership rating of the applicant; the type of expenditure (i.e. exploration or development) and the year in which the expenditure is incurred. Table 3 sets out the percentage levels of incentive payments for oil and gas exploration and development on both provincial and federal lands. It is to be noted that PIP payments are considerably more generous on federal lands than on provincial lands. Recipients must deduct the grants from the cost of the related assets when they are capitalized for income tax purposes.

As mentioned previously (Section 2.10.4), Alberta administers and funds its own APIP.

2.11.2 New Oil Reference Price (NORP) Supplements

The NORP supplements apply to all provinces. The federal government pays supplements on qualifying crude oil and on qualifying pentanes-plus extracted from raw gas provided that the gas stream contains 0.5 percent or greater percentage pentanes-plus by volume.

These supplements apply to production from reserves discovered after December 31, 1980 and from enhanced recovery schemes (other than waterfloods) installed after this date. The amount of the NORP supplement depends on the quality of the oil but averages about $18 per barrel in British Columbia as of November 1982.

Prospects of future gas discoveries are enhanced in Alberta and Saskatchewan to the extent that the supplement on crude oil attracts more exploration in these provinces than in British Columbia. The supplement on pentanes-plus tends to favour Alberta as rich gas pools are more frequent there.

Table 3

PERCENTAGE LEVELS OF PETROLEUM INCENTIVE PAYMENTS (PIP) FOR OIL AND GAS EXPLORATION AND DEVELOPMENT

	PROVINCIAL LANDS				CANADA LANDS			
	Level				Level			
	1	2	3	4	1	2	3	4
	%	%	%	%	%	%	%	%
Exploration:								
1981	nil	nil	25	35	25*	35**	65**	80*
1982	nil	10	25	35	25	45	65	80*
1983	nil	10	25	35	25	45	65	80
1984 on	nil	15	25	35	25	50	65	80
Development:								
1981	nil	nil	15	20	nil	nil	15	20
1982	nil	10	15	20	nil	10	15	20
1983	nil	10	15	20	nil	10	15	20
1984 on	nil	10	15	20	nil	10	15	20
Eligible asset costs:								
1981	nil	nil	15	20	nil	nil	15	20
1982 on	nil	10	15	20	nil	10	15	20

* The 25% Crown Share Incentive.
** Includes the 25% Crown Share Incentive available to all investors.

Canadian Ownership Rating

Level 1 — Less than 50% COR

Level 2 — Must be Canadian-controlled and COR of greater than 50% but less than:

1981 - 60%
1982 - 61%
1983 - 62%
1984 - 63%
1985 - 64%
1986 on 65%

Level 3 — Must be Canadian-controlled and COR of

1981 - 60% but less than 65%
1982 - 61% but less than 67%
1983 - 62% but less than 69%
1984 - 63% but less than 71%
1985 - 65% but less than 73%
1986 on 65% but less than 75%

Level 4 — Must be Canadian-controlled and COR of

1981 - 65% or more
1982 - 67% or more
1983 - 69% or more
1984 - 71% or more
1985 - 73% or more
1986 on 75% or more

2.12 Producer Netbacks and Equivalent Netbacks

2.12.1 Producer Netback

The netback represents the funds available to the producer to cover exploration and development costs and return on investment.

The netbacks developed below are the 'raw gas netbacks' which include the revenues to the producer from marketable gas, gas plant liquids and sulphur.

British Columbia The producer netback in British Columbia is the net field revenue (i.e. the net field price plus the producer liquid revenue), less field operating costs and federal and provincial taxes payable. The average 1982 netbacks were recently estimated by the Ministry as $0.23 per Mcf on old gas and $0.54 per Mcf on new gas for a fully taxable producer (see Appendix 5 for a sample calculation and assumptions). For an individual producer the netback depends on his actual operating costs, which may range from $0.05 to $0.30 per Mcf (average is $0.17 per Mcf). With low operating costs of only $0.05 per Mcf, the netbacks would be $0.29 per Mcf for old gas and $0.59 per Mcf for new gas. Alternatively, a producer with very high operating costs of $0.30 per Mcf would have netbacks of only $0.18 per Mcf and $0.48 per Mcf for old and new gas respectively.

Alberta In Alberta, processing costs, field operating costs, Crown royalties and federal and provincial taxes payable must be subtracted from the gross field revenue (i.e. the average gross field price plus the average by-products revenue) to obtain the netback to a producer. Recently, the Ministry has estimated 1982 annual average netbacks to be in the order of $0.43 per Mcf for old gas and $0.61 per Mcf for new gas, for a fully taxable producer, with a well producing over 597 Mcf per day (see Appendix 5 for a sample calculation and assumptions). The netbacks will

vary for an individual producer depending on his actual gross field price, his actual operating and processing costs as well as the by-products content of his gas stream. Generally, the by-products revenue more than offsets the processing cost. Therefore, a producer with gas containing large amounts of by-products which will require expensive processing, will actually have higher netbacks than a producer with gas containing few by-products and requiring little or no processing.

The assumptions the Ministry used in calculating the Alberta netbacks were generally confirmed by information provided by CPA, IPAC and Dome. CPA estimates that average operating costs in Alberta are somewhat lower than those assumed by the Ministry, but use of their estimate raises netbacks only slightly.

Saskatchewan The producer netback in Saskatchewan is the gross revenue less operating costs, Crown royalties, and federal and provincial taxes payable. The Saskatchewan Department of Energy and Mines has recently estimated the 1982 average netbacks for marketable gas to be $0.08 per Mcf on old gas and $0.21 per Mcf on new gas for a fully taxable producer (see Appendix 5 for calculations and assumptions). Some Saskatchewan producers realize a significant income from gas by-products giving them netbacks on raw gas much higher than those shown above. On average though, Saskatchewan netbacks are substantially lower than those in British Columbia or Alberta.

The province is currently considering proposals which will significantly increase the netbacks to producers.

2.12.2 Equivalent Producer Netbacks

The netbacks discussed in Section 2.12.1 account for prices, costs, royalties and tax rates, which directly affect the producer's return.

Additionally, however, there are other differences between the jurisdictions, including royalty reductions on low productivity wells and special incentives, which must be evaluated in order to make the netbacks fully comparable.

British Columbia Currently, there are no royalty adjustments or other incentives which affect the producer's return.

Alberta The province provides a number of additional incentives, discussed in Section 2.10, which raise the return to producers. For 1982, the value of the royalty tax credit allocated to natural gas only is estimated to be $400 million. (Alberta Department of Energy and Natural Resources (ENR) estimates the total credit to be about $800 million for gas and oil.) This figure is very high because of short term incentives; by 1984, the credit should stabilize at about $170 million for natural gas. The exploratory drilling and geophysical incentives allocated to natural gas are estimated to be worth approximately $67 million for 1981 (DataMetrics estimate). Given the decline of exploration activity in 1982 over 1981, these incentives should be worth about $46 million in 1982. Natural gas production in Alberta for 1982 is expected to be 2,580 Bcf (ENR estimate April, 1982) of which 45 percent will be new gas. Recognizing that the royalty tax credit applies to all gas, and the exploration incentives to new gas only, the value of all incentives in the short term is about $0.16 per Mcf for old gas and $0.20 per Mcf for new gas. In the longer term these incentives may be worth about $0.07 per Mcf on old gas and $0.13 per Mcf on new gas.

The Alberta government also provides for a royalty reduction on marketable gas from wells with low producibility. ENR estimates that, on average, this reduction is equivalent to at least 8 percent in royalty reduction, or about $0.08 per Mcf.

In total, the current equivalent producer netbacks in Alberta are estimated to be $0.67 per Mcf and $0.89 per Mcf for old and new gas respectively. Including the long term incentives only, the equivalent netbacks would be about $0.58 per Mcf and $0.82 per Mcf.

Saskatchewan The province has two incentive programs, as mentioned in Section 2.10, but virtually all of the grants under these programs apply to oil wells.

Table 4

AVERAGE EQUIVALENT PRODUCER NETBACKS (1982)

	Old Gas ($ per Mcf)	New Gas ($ per Mcf)
British Columbia	0.23	0.54
Alberta[1]	0.58	0.82
Saskatchewan[2]	0.08	0.21

1 Long term equivalent netbacks.
2 Does not include netbacks from liquids.

NB. Saskatchewan is considering proposals which would significantly increase producer netbacks.

2.13 Provincial Consumer Rebate or Subsidy

In order to consider the treatment of intraprovincial consumers the Study Group has determined an implied subsidy arbitrarily defined as the difference between the average price paid (or deemed to be paid) for gas by the gas utilities in each province and a comparative gas price of 65 percent of the energy equivalent value of crude oil, inclusive of federal taxes. The points of reference for the calculation of the crude price for each jurisdiction were taken as Vancouver, Edmonton and Regina respectively. Table 6 shows the subsidy for each province.

British Columbia In British Columbia, the implicit consumer subsidy of $1.07 per Mcf is borne primarily by the provincial treasury and also, in part, by the producers.

British Columbia does provide gas consumers with an actual subsidy at this time. For natural gas sold within the province, the domestic utilities pay less than the costs incurred by the BCPC to buy the gas from the producers and have Westcoast gather, process and transport the gas. At present, these costs exceed the average wholesale price by $0.17 per Mcf.

Alberta The Alberta treasury bears the bulk of the $1.02 per Mcf consumer subsidy calculated in Table 5.

Under the Natural Gas Rebates Act, RSA 1980 c.N-5, the Alberta government subsidizes annual gas purchases of up to 1 Bcf per customer. As the support price is set at 65 percent of the Alberta border price, Alberta provides a subsidy of $0.52 per Mcf to the consumer. This subsidy is shown as a deduction on the consumer's bill.

The remaining $0.50 per Mcf of subsidy occurs because gas wholesale prices are not set at 65 percent of oil.

Saskatchewan As calculated in the following table, Saskatchewan's gas consumers are subsidized by $0.86 per Mcf. This is measurably less than the British Columbia and Alberta subsidies because Saskatchewan imports 65 percent of its gas from Alberta at the Alberta border price.

The Saskatchewan producer implicitly subsidizes the Saskatchewan consumer through low field prices for the 35 percent of consumption supplied from within the province. The Minister of Energy and Mines sets the minimum field prices for Saskatchewan gas well below the price Alberta and British Columbia producers receive (i.e. $0.75 per Mcf for new gas in Saskatchewan compared with $1.90 per Mcf in British Columbia).

In addition, the consumer also receives an implicit subsidy through foregone provincial royalties. By setting a low field price the province effectively reduces its royalty revenue per Mcf of gas.

Table 5

IMPLIED GAS SUBSIDIES FOR BRITISH COLUMBIA, ALBERTA AND SASKATCHEWAN

	Provincial Gas Subsidies[1] $ per MMBTU		
	B.C.	Alta.	Sask.
Refinery Gate Crude Oil Price (includes PCC[2] at $6.30/bbl)	$5.71	$5.59	$5.67
Resultant Comparative Gas Price (65 percent of equivalent crude oil price)	3.71	3.63	3.69
Less: Average Provincial Gas Price (paid by utility)	1.81	1.78[3]	2.00
Federal Taxes (NGGLT, COSC)	.83	.83	.83
Equals: Implicit Subsidy	1.07	1.02	.86

[1] All figures expressed in $ per Mcf ($ per MMBTU) as of October 1982.
[2] Petroleum Compensation Charge.
[3] Sum of support price (ie. 65 percent of Alberta border price) plus NOVA cost of service.

2.14 Provincial Consumer Price

Current residential natural gas prices for various jurisdictions are presented at Appendix 6.

British Columbia The wholesale price to each utility is set by the provincial government. The government may direct the BCUC to make recommendations based on public hearings or in-house review but the government is not bound to accept the recommendations in whole or in part.

The price for British Columbia consumers is calculated as follows:

$$CP = WP + NGGLT + COSC + UCOS$$

where CP = Consumer Price
WP = Wholesale Price for that utility
NGGLT = federal Natural Gas and Gas Liquids Tax
COSC = federal Canadian Ownership Special Charge
UCOS = Utility's Cost of Service

Alberta The Alberta border price has been set by agreement between the provincial and federal governments until December 31, 1986. The Natural Gas Rebates Act shelters Alberta residents, commercial establishments and industries from the effects of significant price increases caused by the increasing value of Alberta gas in markets outside the province. The Act provides for the yearly determination of a provincial support price applicable on annual gas purchases of up to 1 Bcf per customer.

The price to Alberta consumers using up to 1 Bcf is calculated as follows:

$$CP = SP + UCOS + NGGLT + COSC$$

where CP = Consumer Price
SP = Support Price which is currently set at 65 percent of Alberta border price
UCOS = Utility's Cost of Service
NGGLT = Natural Gas and Gas Liquids Tax
COSC = Canadian Ownership Special Charge

Utilities receive a provincial government rebate equal to the difference between the price they pay producers for the gas and the support price. Annual consumption in excess of 1 Bcf per customer does not qualify for the support price. Industrial users buying gas directly from producers at more than the support price can apply to the PUB for a rebate on the first 1 Bcf of gas purchased per annum.

Saskatchewan The price to Saskatchewan consumers is determined by the following formula:

$$CP = WPA + WPS + NGGLT + COSC + UCOS$$

where CP = Consumer Price
WPA = Weighted Average Price of Alberta gas based on the Alberta border price
WPS = Weighted Average Field Price of Saskatchewan gas
NGGLT = Natural Gas and Gas Liquids Tax
COSC = Canadian Ownership Special Charge
UCOS = Sask Power's Cost of Service including an adjustment for revenues or losses

3.0 General Assessment

In formulating its recommendations, the Study Group recognizes that certain of the problems now facing British Columbia's natural gas industry cannot be solved easily or immediately. Furthermore, it recognizes that some of these problems involve matters outside the control of the Government of British Columbia or anyone else in the province. The Study Group offers its recommendations, not with the belief that their implementation will resolve all current difficulties, but rather with the view that they will provide an institutional framework which will allow and encourage the affected parties, particularly producers, to create and take full advantage of future opportunities.

A prime example of this is in the area of international marketing of natural gas. British Columbia is confronted with a United States market which will be very difficult to penetrate in the next few years because of the depressed state of the United States economy, the availability of alternate supplies of natural gas from within the United States and from Alberta, and competition from other energy sources, notably residual fuel oil. It should also be noted that regulation of British Columbia gas sales to this market is subject to the jurisdiction not only of British Columbia authorities but also the National Energy Board and the federal government. Realistically, even if all concerned parties in British Columbia and Canada were to agree on a common strategy, it could be some years before the quality of this export market could be restored to something approaching its former state. Nonetheless, it should be recognized that improved sales to this market remain vital to enhancing producers' cashflow and in reducing their current debt load. The Study Group acknowledges the difficulty in expanding this market as being a major constraint to short term solutions.

Recognizing these limitations, the Study Group outlines in this report, a system which should be

sufficiently stable and predictable to enjoy the confidence of the industry while at the same time, meeting the requirements of the government. As well, the proposed system should prove sufficiently flexible to give the industry the greatest possible choice in developing existing supplies, new supplies and markets. Specifically, the Study Group has attempted to frame recommendations which, when implemented, would promote the 300-500 well per year drilling program endorsed by the Minister of Energy, Mines and Petroleum Resources on June 17, 1982, and to have a means whereby the resultant production can be effectively marketed.

The Study Group has attempted to cast its recommendations in terms of principle, without addressing all details of implementation. It believes that for such recommendations as may be endorsed by the government, the detailed method of implementation should be developed by the Ministries and Crown agencies involved in consultation with those most affected. Notwithstanding this, the Study Group has generally satisfied itself as to the practicability of its recommendations.

In implementing the recommendations, all quantitative measures of distance, volume, mass, density, energy content, etc., should be expressed in S.I. units.

3.1 Disposition of Petroleum and Natural Gas Rights

Discussion The general method of disposition of petroleum and natural gas rights is similar in all three provinces. Differences are restricted to details, for example: duration of tenure, rental and issue fees, and provisions for converting exploration permits and licences to lease. The Study Group has noted the concern expressed by industry respondents about the recent increases in rentals, issue fees and work commitments in British Columbia but considers that the changes were justifiable given that fees and related provisions have not been raised since 1974. It observes, however, that the term for permits in British Columbia is longer than in the other two provinces but recognizes that this is kept under continual review by the Ministry.

In the past year or two, some title holders have been drilling the minimum number of wells necessary to protect the titles to the land which they hold. The Study Group attributes this to economic conditions.

The Study Group concludes that the method of disposition of petroleum and natural gas rights in British Columbia is appropriate.

Recommendation

None

3.2 Development of Natural Gas Supply

3.2.1 Exploration and Production

Discussion Exploration and production in all provinces is undertaken by the private sector. In Saskatchewan, two Crown Corporations produce a small amount of gas.

A large proportion of the total gas produced in British Columbia is accounted for by a relatively small number of producers. For example, out of a total of 71 producing companies in the province, the largest - Petro-Canada - was the designated operator for some 33 percent of total British Columbia gas production in 1981. The top five operators, including Petro-Canada, Mobil, BP, Dome and Amoco, accounted for 57 percent of total British Columbia gas production in 1981.

While noting the level of concentration indicated by the foregoing, the Study Group does not believe that it has adversely affected the development of the natural gas industry in British Columbia.

Recommendation

None

3.2.2 Out of Province Supply

Discussion Out of province gas displaces British Columbia gas in the export market served by Westcoast through the Huntingdon-Sumas export point. While Alberta gas has other market outlets (e.g. to export points east of Alberta), Territories gas does not. The Study Group believes that Alberta produced gas now entering the U.S. export market through the Westcoast system should be diverted, wherever possible, to alternative market areas. In this regard, the Study

Group recognizes the recent efforts by Westcoast, Pan-Alberta and the BCPC to achieve this objective. However, the Study Group believes that in any event, the displacement caused by Alberta produced gas should not be permitted to continue after the current contracts expire in 1989. The Study Group notes, in this regard, the undertakings by Westcoast before the NEB that it does not intend to extend its purchase of Alberta gas beyond the expiration in 1989 of existing contracts.

Since it lacks other routes to market, however, it is reasonable that the Territories gas continue to flow through British Columbia, in effect sharing the total market available to British Columbia gas.

The Study Group has certain concerns and recommendations relating to the pricing of the aforementioned Alberta and Territories gas as discussed in Section 3.4.

The Study Group believes that the provision of Alberta gas to the Columbia area in southeastern British Columbia is a practical and economic way to serve this market.

Recommendations

That the government seek guarantees from Westcoast over and above those that exist in the Westcoast/BCPC agreement that British Columbia gas producers will always be offered the first right to purchase contracts for gas to be delivered through the Westcoast system in British Columbia.

That efforts be continued to develop market alternatives for the Alberta supply entering into northeast British Columbia so as to permit more British Columbia gas to be sold in the United States export market.

3.2.3 Gathering, Processing and Transmission

Discussion The construction of the field gathering system in British Columbia is done by the producers and this is the normal and preferred arrangement. Raw gas transmission lines, which exist only in British Columbia, permit large centralized processing facilities with resulting benefits in terms of economies of scale. With respect to those facilities lying between the gathering point metering station and the marketable gas transmission mainline, the Study Group believes, as discussed in Section 3.3, that 'future contracted gas'[1] should be marketed and processed under a new system which permits a greater range of opportunities.

The benefits from this system would relate primarily to the opportunities made available to the producers from becoming involved in the marketing of natural gas and the sharing in by-product revenues. The government would also benefit from any increased sales resulting from an expanded marketing effort.

All marketable gas transmission mainlines in British Columbia are owned and operated solely by Westcoast. In Alberta such lines are provided by NOVA. The major differences are: first, Westcoast buys and sells natural gas whereas NOVA does not; and second, Westcoast is a federally regulated company whereas NOVA is under provincial jurisdiction. The Study Group considers that sole ownership by Westcoast of the marketable gas transmission mainline is appropriate.

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[1] The term 'future contracted gas' refers to gas which is obtained for the purpose of providing a service for which a new or revised sales contract will be required.

Recommendations

That, in respect of gas now under existing contracts, the present gathering, processing and transmission system remain as is.

That, in respect of future contracted gas a producer have the following options:

(a) to sell raw gas at the field gathering point to any buyer (this would be similar to but less restrictive than the current arrangement where the producer sells raw gas to BCPC); and

(b) to retain ownership of raw gas arranging for its transmission (by producer-owned or other facilities) to a gas processing plant (producer-owned or otherwise) and sell marketable gas to any buyer and any by-products to any buyers; where transmission or processing facilities were owned by other than the producer he would pay a fee reflecting the costs involved. If Westcoast provides such service it should recover its full costs and any return thereon. This would require that Westcoast act as a common carrier and common processor.

3.2.4 Straddle Plants

Discussion At the current time there are no straddle plants in British Columbia although one or more may be constructed in the future. Since Westcoast owns the gas in the transmission pipeline, and controls the right of way, the Study Group believes that the NEB would regulate a straddle plant if Westcoast were to build, own or operate it. The province would, however, also exert a measure of jurisdiction over such a project through the provisions of the Energy Review Process under the Utilities Commission Act. On the other hand, a facility built, owned and operated by an entity not under federal regulation would be exclusively regulated by the province. The Study Group believes that the

direct relationship between straddle plants and development of a petrochemical industry in the province makes provincial jurisdiction over such plants highly desirable.

Further processing of natural gas into petrochemicals - one of the key elements of British Columbia's industrial policy - would be most effectively implemented with exclusive provincial control over feedstock supply. It is the Study Group's view that federal regulation of straddle plants would represent an unnecessary encumbrance upon prospective development.

Recommendation

That any future straddle plants in British Columbia should be built, owned and operated under exclusive provincial jurisdiction. The implementation of this recommendation is related to recommendations discussed under Section 3.3.2 respecting the regulation of Westcoast.

3.2.5 Underground Storage

Discussion There is no underground gas storage in British Columbia at the present time. Storage of marketable gas can provide economic benefits in terms of efficient delivery of gas.

Downstream storage provides an alternative to expanding the transmission system. With Westcoast's current level of sales (i.e. below system capacity) the economic attractiveness of downstream storage is not great. However as sales and peak demand increase, downstream storage will become increasingly beneficial. In addition, downstream storage could facilitate service to the peak demand market in the United States.

Upstream storage in the producing areas of northeast British Columbia could also be of economic

benefit for load levelling the supply of gas and to provide some relief in the event of the shut-down of processing facilities.

The Study Group believes that implementation of the tariff recommendations set out in Section 3.4.5 would provide further financial encouragement to utilities to pursue downstream storage.

Recommendations

That, in the case of downstream storage, the Ministry consider re-posting Crown petroleum and natural gas rights in the Fraser Valley in order to promote early exploration drilling which could also result in the discovery of a reservoir suitable for gas storage.

That the Ministry also invite requests for exploration permits from parties interested in underground storage only.

3.3 Marketing Arrangements - Agency Roles

Introduction

The marketing arrangements for natural gas in British Columbia differ substantially from those in Alberta. British Columbia operates under a system of a Crown Corporation (BCPC) and a federally regulated utility (Westcoast) with little freedom of action left to the producer compared with the more open system of Alberta with its provincially regulated utility (NOVA) and the extensive rights of producers. The Saskatchewan system, like that in British Columbia, provides little freedom of action to the producers.

The Study Group believes the first steps in improving the marketing of gas in British Columbia relate to the roles of the producers, Westcoast and the BCPC. As was stated in Section 3.0, the general objective of the Study Group in this area is to allow the industry as a whole to take maximum advantage of present and future marketing opportunities.

As was the case in Section 3.2, many of the changes proposed in this section apply only to 'future contracted gas', as defined below and do not affect existing contractual arrangements between producers, the BCPC, Westcoast and the distribution utilities and export customers. The Study Group decided that, as a general rule, retroactive changes to existing contractual arrangements should not be recommended.

'Future contracted gas' is defined in Section 3.2.3 as gas which is obtained for the purpose of providing a service for which a new or revised contract will be required. Therefore, if a producer, the BCPC or Westcoast or some other party wishes to take advantage of the new, more flexible marketing arrangements proposed herein, they would have to find a new market. This could involve a sale of gas to a totally new consumer or a sale to an existing consumer following the expiration or revision of any current contract or service.

It should be emphasized that the distinction in question is between present and future gas service rather than present and future gas supply. Not all future gas supply contracts will meet the definition of future contracted gas, since it may, for example, be necessary for the BCPC to acquire additional gas supplies to meet its obligations to Westcoast under the Basic Agreement which provides that the BCPC will supply Westcoast with all the gas necessary to meet Westcoast's existing contracts of service with domestic utility companies and with Northwest Pipeline. (The bulk of the contracts of service with the domestic utilities expire in 1991, while the contract with Northwest Pipeline expires in 1989.)

It should also be noted that the Study Group believes that a further small restriction would have to exist even in the case of future contracted gas. The restriction relates to the marketing of sulphur by producers and others. From information of a general nature provided by the BCPC in respect of its contractual obligations to sulphur purchasers, it would seem that, even in the case of future contracted gas, the producers could only market their own sulphur where it was recovered from gas processed at a plant other than the Fort Nelson, Fort St. John or Pine River plants. Otherwise, the BCPC would have to be used at least as an agent for the sale of such sulphur.

A number of the recommendations in this section are interrelated and, in turn, relate to recommendations in other sections, particularly those dealing with facilities, royalties and pricing. Where such a relationship exists, it has been noted by means of an appropriate cross-reference.

3.3.1 Producers

Being essentially bound to sell their gas to the BCPC, British Columbia producers have no opportunity to arrange their own markets, to construct or arrange for raw gas transmission facilities, gas processing

facilities and marketable gas transmission laterals or to recover and subsequently market natural gas by-products.

The Study Group believes that it would be beneficial to the industry and the province if the producers had a full range of options respecting the gathering, processing, and marketing of their gas. Not only would this be more equitable, but additionally, if the producers were able to participate actively in the marketing of gas, it is likely that they would develop innovative methods to expand sales.

The arrangement envisaged here foresees a number of companies or groups of companies becoming involved in selling gas in all markets, including internationally. While this proposed diversification of marketing is, on the whole, desirable, it introduces the danger that large United States buyers would play prospective gas sellers off against one another. The problems associated with this could be avoided, however, by creating a small informal gas marketing advisory committee.

As envisaged, the committee would take initiatives to provide advice to producers, other marketers and the provincial government respecting the terms for new gas sales contracts. The terms of reference established for this committee would define the objectives and criteria upon which it would base its advice.

Recommendations

That, in the case of gas which has been or will be purchased for the purpose of meeting existing contracts of service, the present marketing arrangements remain in place.

That, in the case of future contracted gas, producers have the options of selling raw gas or

retaining ownership of raw gas to permit their direct involvement in the marketing of the resulting marketable gas and its by-products (subject only to a limited restriction respecting the marketing of sulphur).

That producers have the option of marketing future contracted gas, either raw or marketable, through the BCPC or Westcoast or any other buyer, or to pay commissions to others who would market gas as agents, as described in Section 3.3.2.

That, if favoured by producers, a committee be established by the Ministry, with representation from the BCPC, Westcoast and producers, to provide advice respecting gas marketing.

3.3.2 Westcoast

In general terms, the Study Group believes that Westcoast should retain its rights and responsibilities with respect to all current existing contracts, including the agreements with the BCPC, with the distribution utilities and with Northwest Pipeline. With respect to the transportation, processing and marketing of future contracted gas, as defined in the preceding section, the Study Group anticipates a change in Westcoast's traditional role as described in the recommendations which follow.

As indicated above, the Study Group believes that Westcoast should be given the opportunity to purchase future contracted gas directly from producers. In this way, Westcoast would become even more actively involved in the search for new markets for British Columbia gas. Also, to facilitate the transportation and processing of gas owned by an entity other than Westcoast, it is necessary that Westcoast must also offer the services of a common carrier and common processor.

It should be noted that the Basic Agreement provides that if new markets are within British

Columbia, then the BCPC may require Westcoast to assign to the BCPC any future gas purchase contracts made to service such markets. The Study Group believes, however, that the BCPC should not exercise this right, but that it should have the power to protect itself in one particular circumstance. This would be if Westcoast and an existing domestic customer were to agree to cancel their existing contracts prior to the currently specified expiry date. If the BCPC had itself entered into gas purchase contracts in anticipation of serving the domestic market in question until the expiry date of the existing contracts, then the BCPC should have the power to cover its take-or-pay exposure by frustrating any attempt to set up a new service in substitution of the existing one.

In addition to the basic recommendation concerning future contracted gas, the Study Group also believes that significant benefits to the industry and the province can be obtained through alteration of the NEB's current practice of regulation of Westcoast.

One specific concern relates to the current export licence and the contract between Westcoast and Northwest Pipeline. Neither of these documents contains an acceptable take-or-pay obligation, with the result that significant volumes of natural gas are 'tied-up' while actual sales have declined to the extremely disadvantageous levels described in Section 2.3. The AGBC has recently made submissions to the NEB respecting this problem and the Study Group believes that these representations should continue.

A second specific concern is that Westcoast is now permitted to account for taxation on a normalized basis.[1] Concerns have been raised in the material

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[1] Taxation on a normalized basis allows a company to include an allowance for taxes in its current year cost of service even though payment of these taxes may be deferred to some time in the future.

sent by producers to the Study Group about this method of treatment of taxes for the Westcoast rate base. In addition, TCPL was recently required by the NEB to account for its taxes on a flow through basis.[2]

The Study Group believes that, under present circumstances of low sales volumes and relatively high cost of service, it would be appropriate to have Westcoast account for its taxes on a flow through basis.

In addition to the foregoing, the Study Group has also considered a more fundamental question - namely, whether or not Westcoast, with its present and anticipated future role, should be controlled by the NEB.

Historically, the NEB's jurisdiction over Westcoast arose from the company's status as an interprovincial and international transporter and marketer of natural gas. When Westcoast first began operations, most of the gas flowed from Alberta and British Columbia to the United States. Since then, however, Westcoast has evolved into an entity with very significant intraprovincial impact. These intraprovincial activities of Westcoast are crucial to British Columbia's natural gas industry.

As previously indicated, the NOVA pipeline system has not been, and is not now, subject to NEB jurisdiction. Indeed, the NOVA system has been designed, with its facilities stopping just short of the Alberta border, to remain entirely under provincial regulatory control. The physical function that Westcoast now performs is little different from that of NOVA, with Westcoast's percentage of gas transported to intraprovincial customers being even larger than that of NOVA.

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[2] Taxation on a flow through basis requires a company to include in its cost of service only those taxes which it must pay in that year.

The Study Group believes that there are sound policy reasons supporting the proposition that Westcoast's intraprovincial utility activities should be exclusively regulated by provincial authorities. The basic reason is that this would provide a framework under which Westcoast's rate and facility applications could be handled in a more orderly, more responsive, and less confrontational manner than has existed. The extension of the gathering and processing system to open up new areas, as well as the expansion of the marketable gas transmission mainline system, would then be under the same authority as that responsible for the distribution system and wholesale and field pricing. This would facilitate a consistent and rational scheme of regulation covering all aspects of the natural gas business.

The Study Group also believes that the construction and operation of straddle plants to supply feedstock to potential petrochemical operations could be more readily undertaken, in line with provincial economic policy, if these were under provincial jurisdiction. Additionally, consistency with applicable provincial environmental legislation would be more readily assured with provincial regulation of the intraprovincial utility activities of Westcoast.

In reaching this conclusion, the Study Group recognizes that the issue is not a simple one and that any changes would best be made through a process of careful negotiation so as to achieve a result which respects the interests of all concerned parties. For example, such a result could involve an arrangement whereby the province assumed jurisdiction over gas transmitted to a point just short of the United States border. This, of course, could only occur when Alberta gas was backed-out of the Westcoast system. The Study Group believes that the transportation of the small volumes of gas currently flowing from the Territories is incidental to the question of jurisdiction and the continuation of this feature of the present system should not be permitted to preclude a transfer of regulatory jurisdiction. (Any new pipeline designed to carry

British Columbia and Alberta gas to an LNG facility would be interprovincial and remain under the jurisdiction of the NEB.) The Study Group believes that this process of negotiation should commence forthwith with a view to establishing, at the earliest practical time, the new framework discussed above.

None of the other recommendations in this report, concerning Westcoast or otherwise, depend on the success of the proposed negotiations. Should the recommendation to commence such negotiations not be accepted, or should a decision in this regard be deferred, it would not affect the other recommendations in this report.

At the same time, however, there is a certain relationship between this jurisdictional recommendation and the basic recommendation that Westcoast be allowed to purchase future contracted gas directly from producers. Neither recommendation is dependent upon the other, but the Study Group believes that the basic recommendation could enhance the prospect of a transfer of jurisdiction. As indicated above, one effect of the basic recommendation would be to involve Westcoast even more directly in the area of natural gas marketing. While the Study Group believes this expanded role to be desirable, it also believes that the marketing function is one that should be kept separate from Westcoast's utility functions. Accordingly, the Study Group would suggest that Westcoast separate these two functions, preferably by forming a separate new company which would only be responsible for intraprovincial utility operations. If this approach were to be taken, it would have the desirable feature of facilitating the proposed transfer of jurisdiction. The new company could be clearly under provincial regulatory jurisdiction while the parent company, with its intra and interprovincial and international marketing business, would still be regulated by the NEB. Thus, there would be two entities, corresponding in many ways to the situation in Alberta with NOVA and Pan-Alberta.

Recommendations

That Westcoast's role under its existing contracts be continued until such time as the contracts expire.

That Westcoast continue to be the sole and exclusive owner and operator of existing pipeline and processing facilities.

That Westcoast act as a common carrier and processor for future contracted gas.

That Westcoast be given a non-exclusive right to purchase, gather, process and market future contracted gas and to receive commissions or fees for gathering, processing or marketing such gas that would reflect the true cost of service of transporting and processing the raw gas.

That the provincial government continue to make representations to the NEB respecting the necessity of a take-or-pay obligation on Northwest Pipeline for the purposes of the existing export Licence GL-41.

That the government endorse the representations that producers intend to make to the NEB in support of having Westcoast's taxation accounted for on a 'flow through' rather than 'normalized' basis.

That the Ministry, and the AGBC be charged with investigating ways and means, including seeking the advice and cooperation of Westcoast, the NEB, the federal government and any other concerned party to bring Westcoast's activities in gathering, processing and transporting British Columbia gas within the province under provincial control.

3.3.3 The BCPC

The Study Group recognizes the role of the BCPC in strengthening the British Columbia jurisdic-

tional position respecting the ownership and control of natural gas, in collecting the economic rent for the government, in representing the British Columbia interest in Westcoast rate applications before the NEB, in assisting in the development of gas markets and in facilitating the implementation of government policy respecting the natural gas and petrochemical industries.

The Study Group believes that most of these roles should continue, especially with respect to existing contracts. However, the Study Group also believes that there should be a shift in the primary focus of the BCPC, away from gas purchasing and revenue collection towards an expanded but not exclusive role in natural gas marketing.

As indicated above, the Study Group believes that the BCPC should continue, in respect of future contracted gas, to have the option of purchasing either raw or marketable gas from producers. At the same time, however, the Study Group believes that the BCPC should not continue to enter into gas purchase contracts which provide that the BCPC would, in effect, guarantee the return on the facilities necessary to transport and process raw gas. The Study Group is of the view that this is a financial risk which is inappropriate for a Crown Corporation. Accordingly, the Study Group proposes that the BCPC should require in its future raw gas purchase contracts that all such risks be borne by the producer. The implementation of this would be simply achieved by providing that the price of gas payable under all such contracts would reflect the true cost of service of transporting and processing the raw gas.

In addition to those situations where the BCPC had purchased gas for its own markets, the Study Group believes that it would be prudent to require that the BCPC should continue to acquire at least a temporary ownership position in all future sales of gas so as to safeguard the jurisdictional interests of the province. In those sales where the BCPC was not otherwise a party,

this temporary ownership position would be similar to that taken in Alberta by the APMC, whereby the corporation purchases and immediately resells the gas to the same party.

Recommendations

That the BCPC continue to act as the purchaser of raw gas under existing contracts and as the seller to Westcoast under the Basic Agreement with Westcoast.

That the BCPC continue its role in monitoring Westcoast's cost of service and making appropriate submissions thereon to the NEB, so long as the NEB retains jurisdiction over Westcoast's utility functions.

That the BCPC be given the opportunity but not the exclusive right to purchase future contracted gas on the basis that the price specified in such contracts of purchase would reflect the true cost of service of transporting and processing the raw gas.

That the BCPC acquire a temporary ownership position in future contracted gas to safeguard British Columbia's jurisdictional interests.

3.3.4 Implementation Matters

The Study Group has satisfied itself with the general practicability of its recommendations but believes that certain implementation matters will deserve special consideration. Examples of these are as follows:

1. It will be necessary to provide for the possibility that a provincial or federal regulatory agency may not permit a producer to sell his own gas to a new U.S. market on the basis that the contracted quantities in the existing Westcoast/Northwest

contract are not being used to full capacity. This problem may be avoided if the NEB accepts British Columbia's position respecting Northwest's take-or-pay obligations, as discussed in Section 3.3.2.

2. Provisions must be made to provide the BCPC with a first right to market those existing deficiency volumes it has paid for but which it has not taken.

3. The new role envisaged for the BCPC will require a new method of providing for its administration costs.

4. It will be necessary to establish an appropriate method for setting and allocating the cost of service for gathering raw gas, transmission and processing to individual producers.

3.3.5 Overview

As indicated above, the Study Group does not propose any changes in respect of marketing arrangements for gas which has been obtained to provide service under an existing contract. Those arrangements are shown in Figure 1.

With respect to future contracted gas, the essential points in the proposed new marketing arrangements are as follows:

(a) a producer may sell either raw or marketable gas to any party;
(b) Westcoast may purchase gas directly from the producer and market it thereafter, preferably as a separate marketing function;
(c) the BCPC may also purchase raw or marketable gas, on the basis that the price paid for the raw gas would reflect the true cost of service of transporting and processing the raw gas as allocated to the producer; and
(d) it would be highly desirable that Westcoast's intra-provincial utility operations be brought under

provincial regulation while Westcoast's present and future marketing operations remain under NEB control.

The proposed new marketing arrangements are shown in Figure 2.

FIGURE 1

EXISTING MARKETING ARRANGEMENTS

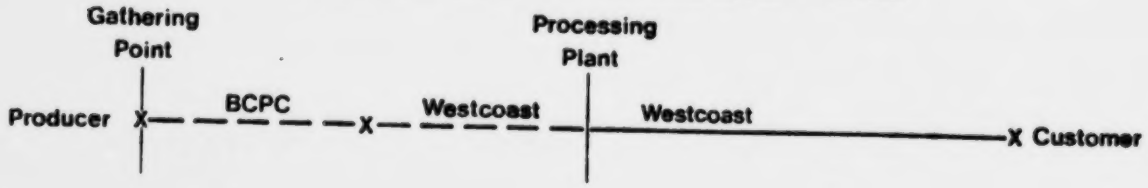
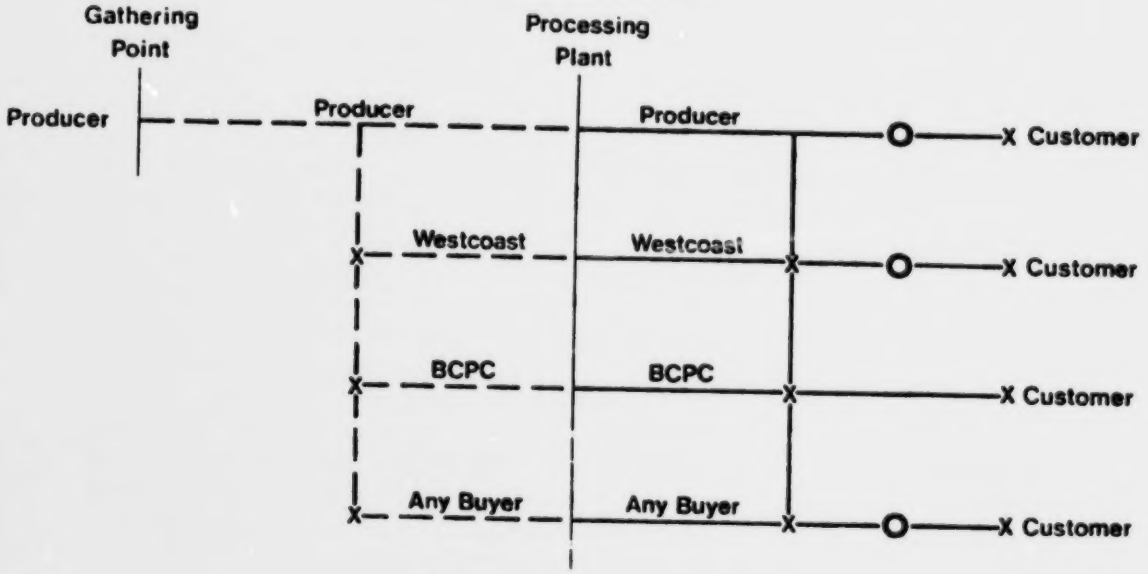


FIGURE 2

MARKETING ARRANGEMENTS FOR FUTURE CONTRACTED GAS



LEGEND

Raw gas

Marketable gas

X — Possible point of sale

O — Back-to-back purchase/sale with the BCPC

Any party may buy/sell from any other party

3.4 Pricing and Related Matters

Introduction

In the text that follows, all values are expressed in terms of $ per Mcf assuming MMBTU's per Mcf. The Study Group considers that energy units expressed in S.I. (e.g. $ per gigajoule) should be employed in the implementation of its recommendation.

Recommendation

That prices of natural gas at the wholesale or field level be expressed in $ per GJ.

3.4.1 Domestic Gas Pricing

Wholesale Price

The approach used in setting British Columbia's natural gas wholesale prices is both unpredictable and cumbersome. This results from the province's reliance on irregular and expensive public hearings followed by a decision by Cabinet. Under this scheme, both wholesale and field prices are unduly subject to current political considerations regarding consumer prices - a matter which can be more appropriately dealt with in other ways (see Section 3.13).

The Study Group favours a wholesale pricing scheme which would relate the price of gas to the value of energy in the marketplace. There are two practical alternative measures of this value - the Alberta border price and a price equal to some percentage of an energy-equivalent amount of crude oil. The Alberta border price is set by a known schedule until 1986 and is a key determinant of producer returns in Alberta. The national pricing policy for natural gas, on the other hand, links gas price, after the federal Natural Gas and

Gas Liquids Tax, to 65 percent of the price of an energy-equivalent amount of crude oil in Toronto.

The Study Group recognizes that the 65 per percent figure is totally arbitrary but that it is reasonable at the current time. To the extent that the international oil price can be forecast, a pricing policy based on oil price provides some degree of predictability.

The level of wholesale prices recommended by the Study Group were developed having regard for the royalty scheme recommended in Section 3.6 and the netback targets set out in Section 3.12. These price levels, therefore, are an integral component of the package of pricing and royalty recommendations designed to achieve the government's overall objectives in terms of increased exploration effort. (Direct industrial sales at a discounted price are not excluded by this approach to wholesale pricing. See Section 3.5.)

Recommendations

That the system average wholesale price of natural gas move immediately to equal the Alberta border price for the years 1983 and 1984.

That commencing in 1985 the system average wholesale price move in equal yearly steps to a minimum of 65 percent of the energy-equivalent cost of crude oil at the Vancouver refinery gate by 1990 so that:

(a) producer netbacks achieve the levels recommended in Section 3.12 when calculated under the royalty scheme recommended in Section 3.6;
(b) consumer retail prices after any provincial subsidy be at acceptable levels; and
(c) reasonable provincial revenue goals be met.

That, if circumstances change and the federal government revises its 65 percent figure, the province also review this matter in light of the particular circumstances existing at that time.

Producer Price As with wholesale pricing, the method of setting field prices in British Columbia is arbitrary and unpredictable. This, in fact, was by far the most common complaint made by the industry respondents to the Study Group.

The Study Group believes that the producer price for gas sold within British Columbia should be directly related to the wholesale price by deduction of the appropriate cost of service. For natural gas which is sold at a premium price in export markets, the Study Group believes the revenue associated with the premium should be distributed ratably to all producers in proportion to their marketable gas production. Such a relationship between the wholesale price and the field price, and the 'flowback' of export premiums to all producers would be similar to the practice in Alberta.

Recommendations

That the price at the gathering point for marketable natural gas sold intraprovincially, be a price derived by deducting the appropriate cost of service from the system average wholesale price.

That an export flowback scheme be instituted to allow all producers to share in the benefits from the export market ratably in proportion to their production of marketable gas.

3.4.2 By-Product Pricing

Discussion The Study Group agrees that by-product prices should be determined in the open market as they are at present.

Recommendation

None

3.4.3 Pricing Out of Province Gas

Discussion

The Alberta and Territories gas now being delivered into British Columbia is deemed to be exported to the United States and therefore reduces the total export market available to British Columbia gas producers. The Study Group questions the rationale for this and particularly the fact that Alberta and Territories gas receive the export price. The Study Group believes that instead this gas should receive a price reflecting a weighted average of sales within British Columbia and the export market.

The Study Group notes that this position was put forward by Westcoast during the recent NEB Omnibus Gas Export proceeding and that the province of British Columbia supported Westcoast in this regard at the hearing.

Recommendation

That steps be taken to base prices for Alberta and Territories gas now being exported through British Columbia to the United States on a weighted average price received by producers of British Columbia gas from their total sales of marketable gas.

3.4.4 Export Pricing

Discussion

The Study Group does not believe that the present method used by the federal government to set the export price of natural gas is realistic in light of the current and prospective market situations. The Study Group recognizes that in the past the province has made representation to the federal government that the price remain at U.S. $4.94 per MMBTU, the price which has prevailed for some time.

The NEB is currently reviewing the extent of the Canadian natural gas surplus and is expected to extend the term of some existing export licences and perhaps issue some new licences in the near future. However, the U.S. market is particularly weak at present and it is not clear that the volumes of gas under the proposed new contracts to U.S. buyers will actually be sold.

The Study Group does not believe that lower prices on a broad basis would necessarily increase export revenues, particularly in the case of British Columbia gas which faces competition in the Pacific Northwest from U.S. gas and residual fuel oil. Rather, the Study Group advocates the abandonment of the present rigid pricing system in favour of a 'package approach' to new export contracts. This approach would see price determined between seller and buyer as part of a 'package' of contractual terms including such matters as load factor and term. The Study Group believes that this approach would improve long term revenues to the industry and the province.

The Study Group recognizes the extensive debate now occurring on the matter of U.S./Canada natural gas trade. Numerous specific pricing proposals have been put forward by a variety of groups on both sides of the border. The Study Group has not, however, evaluated these proposals and instead has framed its recommendations in terms of principle.

Recommendation

That the provincial government adopt the position and urge the federal government to accept that the present rigid export pricing system be replaced by a system where producers or producer's agents would negotiate with export buyers, on an arms-length basis, the terms of export contracts which would then be subject to approval of the provincial and federal governments. These terms would include, among other

matters, volume, price, take-or-pay commitments, peak day and annual deliveries, and duration. In their separate reviews of the export 'contract package' the provincial and federal governments would have regard for the public interest involved, the perceived commodity value of the gas, the price to Canadians, the cost of service and other relevant matters. Only those 'contract packages' which met such tests would be approved.

3.4.5 Westcoast System Tariffs

Discussion

Unlike the situation in Saskatchewan and Alberta, the company in British Columbia responsible for natural gas facilities, other than distribution, is regulated by the NEB. The NEB has, however, agreed to allow the province full jurisdiction over the wholesale price of natural gas, including the allocation of the NEB-determined cost of service.

The demand/commodity type of pricing for natural gas transmission systems is widely utilized, primarily because it is an effective way of ensuring that the prices paid by each customer reflect the true cost of the service provided him (by having the demand charge reflect the fixed elements of the cost of service). At present, however, British Columbia does not implement a true demand/commodity type of pricing. All recent increases in the wholesale price for natural gas have been in the form of increases to the commodity charge, while the demand charge for the Westcoast system has remained static for several years.

The BCUC, in its 1980 report to the Lieutenant Governor-in-Council entitled, "1980 Natural Gas Price Inquiry Report", recommended that updated demand/commodity rates should be phased in over the next three years. The provincial government accepted the recommendation in principle, but has yet to implement it.

Recommendation

That the government request the BCUC to design an appropriate tariff structure for the allocation of Westcoast's cost of service along the lines recommended in its "1980 Natural Gas Price Inquiry Report".

3.5 New Market Development

Discussion

In the Study Group's view this is an exceptionally difficult time to market gas. In spite of this, however, it is the Group's view that the existing arrangements for market development are unsatisfactory and that steps should be taken now to improve this in order to get the most from the market when it turns around.

The Study Group concludes that more parties should be encouraged to seek out new markets and be allowed to enter into agreements for the sale of gas (see Section 3.3). Specifically, in addition to Westcoast, the Study Group believes that, with certain provisos, BCPC, producers and producer groups should be authorized and encouraged to enter into contracts for direct industrial sales in the intraprovincial market and with any new international customers.

The Study Group also recognizes the important role of provincial utilities in developing new markets and protecting existing markets. Active marketing efforts by the utilities should be continued and expanded.

The Study Group endorses the new market development activities of the government in support of CNG as an alternative transport fuel; the use of programs such as the Gas Extension Assistance Program; and the decision of the government to pursue the possibility of shipping gas to Vancouver Island. All of these are important and necessary steps toward increasing domestic gas sales.

Recommendations

See Section 3.3 where the majority of the Study Group recommendations on new market development are made.

That direct industrial sales would be authorized only where:

(a) the customer requires gas at prices below the utility gas rates;
(b) producers are prepared to sell at a discount; and
(c) the utility company franchised to serve the area in which the industrial customer is located maintains all rights to carry the gas and recover its full cost of service.

That the provincial government:

(a) continue to develop new markets for gas (e.g. CNG) and to protect existing markets;
(b) review the Gas Extension Assistance Program to determine whether it should be extended to other areas of the province; and
(c) continue to emphasize further processing of natural gas as an element of its industrial/economic development policy.

3.6 Royalties

3.6.1 Natural Gas

Discussion There is a major difference between the British Columbia and Alberta systems of collecting 'economic rent'. The British Columbia system, wherein BCPC pays the producers a government-set field price out of the revenue it receives from Westcoast, remitting the difference to the government, is artificial and not predictable. Moreover, in recent circumstances it has actually led to negative equivalent royalties. The Alberta system, by contrast, employs a royalty percentage which is applied to a rationally determined, reasonably predictable field price.

The producer responses to the Study Group's invitation for opinions were strongly weighted in favour of an explicit royalty system having some permanence and predictability. Recent studies of the Ministry have also concluded that a formula-based explicit royalty system should be adopted. The Study Group agrees with these views. Furthermore, an explicit royalty system is important in order to implement the recommendation in Section 3.3 that the producer be permitted to sell gas to a range of purchasers. The Study Group's recommendations in Section 3.4 relating the gross field price to the wholesale price and a 'flowback' of export premium paves the way for such a royalty system.

The Study Group has reviewed the Alberta royalty formula and the background work done by the Ministry. The Alberta formula distinguishes between 'old' and 'new' gas while the past studies of the Ministry suggest a distinction between 'old', 'new' and 'incentive' categories. The purposes of such distinctions are twofold: a) to recognize that 'old' gas was developed at a lower cost than 'new' gas and therefore could tolerate a higher royalty; and b) to spur exploration and development through a lower royalty for 'new' or 'incentive' gas. In both the Alberta

formula and those suggested by the studies of the Ministry, the royalty rate increases with increasing price, reflecting an increase in ability to pay.

The Study Group endorses all these concepts but believes it appropriate, while recognizing the roles of increasing price and 'age', to recognize also the other principle factors affecting cost. Accordingly a formula in which the royalty rate is related to the principle factors affecting cost as well as to the price is considered appropriate. Such a concept may be expressed as:

$$R\% = f(CRF's, PF)$$

where $R\%$ = Royalty Rate
f = Function of
$CRF's$ = Cost-Related Factors
PF = Price Factor

Among the very many factors which influence the unit cost of finding and producing gas in British Columbia, the Study Group considers the following to be the most important: time of first production from well; location and topography; well depth; and production rate. A relatively simple manner in which subjective allowance for the cost-related factors may be made and account taken of the price factor is described in Appendix 7.

The resulting royalty formula is:

$$R\% = R\%_{max} \ (1 - e^{-kP})$$

where $R\%$ = actual royalty rate, being a fraction of $R\%_{max}$ depending upon the level of 'P'
$R\%_{max}$ = maximum royalty rate determined as the sum of cost-related factors
k = a constant
P = total field price

The Study Group believes that it is desirable and practical to introduce the explicit royalty system with royalty paid to the Mineral Revenue Branch of the Ministry for all production in the province. In the case of production under existing producer/BCPC contracts the Study Group is of the view that the explicit royalty system should be introduced either by amendment to the contracts through negotiation or legislation, or alternatively within the framework of the present contracts and the BCPC/Westcoast agreement, whichever is determined to be the more practical. A method of achieving the latter is described in Appendix 7. In the case of 'future contracted gas' as that term is used in Sections 3.2 and 3.3, the Study Group believes that payment of royalties directly to the Mineral Revenue Branch of the Ministry should be provided for in the new contracts.

The Study Group has determined that the application of the proposed royalty formula, with numerical data as shown in Appendices 5 and 7, would give producers the netbacks it considers appropriate to encourage the desirable level of producer activity in the province.

Recommendations

That British Columbia, at the earliest opportunity, introduce the proposed explicit royalty system set out in Appendix 7.

That the royalty system be applied to all gas produced in the province including gas sold to the BCPC under existing contracts.

That the royalty payments be collected by the Ministry.

3.6.2 By-Products

Discussion The present method of distribution of revenue between producers and the BCPC (i.e. the 12.5 percent/87.5 percent split) is based on historical precedent and has no discernible relation to current costs and benefits. The Study Group believes that the arbitrary features of the existing arrangement could be removed by applying the proposed royalty to the total revenue derived from raw gas. In such a case the value of raw gas for royalty purposes would be determined by adding the revenue allocated to producers from the sale of the by-products to the proceeds from the sale of marketable gas including the flowback from export markets and deducting the cost of service. The revenues and costs should be allocated back to producers by a suitable method to be developed or approved by the Ministry.

Recommendations

That the Ministry, in consultation with producers, the BCPC and Westcoast, develop a suitable method by which both the revenue from by-product sales and the cost of service can be allocated to producers and included in the total field price for royalty purposes.

That the Ministry work with the BCPC to develop the most practicable way to bring by-product revenues from gas under existing contracts under the royalty scheme.

3.7 Provincial Taxes

Discussion The Study Group notes that British Columbia has the highest provincial corporate tax rate of the three western provinces (16 percent compared to Saskatchewan's rates at 14 percent in general or 11 percent for those qualifying for the federal small business deduction and Alberta's rate at 11 percent).

Provincial taxes affect producer return and therefore have a bearing on producer incentives for exploration and development activities.

Recommendation

That British Columbia continue its current practice of providing income tax rebates for royalty payments.

3.8 Federal Taxes

Discussion The Study Group believes that both the COSC and the NGGLT operate in a manner counter to the federal government's declared intention of encouraging the expansion of the natural gas market. In particular, these taxes have a serious negative impact on gas based petrochemical development.

The PGRT also has an impact on petrochemical development because it restricts the amount a producer would be willing to discount his gas price.

Recommendation

That the province continue to urge the federal government to abandon both the COSC and NGGLT or, as a minimum, to reduce their negative impact on market expansion for natural gas.

3.9 Differences in Producer Costs

Discussion The Study Group has observed the difference in producer costs between the three western producing provinces and recognizes that the higher costs in British Columbia are a negative factor toward development. This is in part a consequence of the higher sales taxes in British Columbia.

The Study Group has endeavoured to account for differences in producer costs in British Columbia, Alberta and Saskatchewan including the impact of sales taxes in the design of the proposed pricing, royalty and incentive system for British Columbia.

Recommendation

None

3.10 Provincial Producer Incentives

Discussion The Study Group notes that while both Alberta and Saskatchewan have special incentives to stimulate exploration for and development of natural gas supplies, there are no comparable incentives in British Columbia. Conceptually, the Study Group does not favour such incentives and believes the appropriate conditions for industry activity should flow from access to markets, rational pricing, reasonable cost and price sensitive royalties and non-discriminatory taxes on corporate profits. It recognizes the special circumstances of the day, however, which have led Alberta and Saskatchewan to introduce a number of special incentives.

Facing the practicalities of the situation, the Study Group believes that British Columbia should introduce a short-lived specific program to stimulate natural gas exploration in the immediate future.

Recommendation

That the province introduce a royalty holiday of 24 producing months for qualifying wells. Qualifying wells would be those drilled in the 12 months starting at the date of the implementation of this recommendation and which are classified as exploratory wells under the Petroleum and Natural Gas Act, R.S.B.C. 1979, c. 323. (Based on reasonable assumptions respecting the number of wells to be drilled and reserve additions, the value of the royalties foregone due to this incentive recommendation would be in the order of $20 million, spread over the late 1980's.)

3.11 Federal Producer Incentives

Discussion The Study Group observes that PIP, as currently implemented, tends to encourage the development of the more expensive frontier reserves ahead of the less costly reserves under provincial lands.

Recommendation

None

3.12 Producer Netbacks and Equivalent Netbacks

Discussion The Study Group recognizes that netback, while a major indicator of the economic attractiveness of exploration and development expenditures, is not the only factor considered important by producers. The pre-production costs and the time interval between discovery and commencement of commercial production are among the several other significant factors. Notwithstanding their limitations, however, the Study Group believes that appropriately calculated netbacks provide a basis for judging whether or not a pricing and a royalty regime will help to provide an economic environment which will stimulate exploration and development. The Study Group is of the view that average netbacks, both for previously discovered and yet to be discovered gas in British Columbia, will have to be in the order of Alberta netbacks in order to stimulate drilling activity to a satisfactory level.

The Study Group also recognizes, however, that an accurate evaluation and comparison of equivalent netbacks in the two provinces is difficult to achieve and, in fact, can vary between producers. In addition, while an allowance for higher drilling costs in British Columbia should be made (see Section 3.9), this allowance would vary with the nature of drilling operations.

The Study Group believes that the royalty system proposed in Section 3.6 with the numerical data in Appendix 7 allows for these factors. When cost related factors are high and production is in the early stages, the producer netbacks in British Columbia will exceed those in Alberta. They should also provide adequate incentive to meet the objectives of an eventual level of drilling activity of more than 300 wells per year as experienced from 1978 through 1980. It is also noted from these years that adequate producer netbacks and a high level of drilling activity is accompanied by substantially increased activity by producers in the

acquisition of petroleum and natural gas rights at Crown lease sales. In fact the revenue collected by the government from these sales is an important offsetting factor to the results of any decrease in royalties that may be required to achieve adequate producer netbacks.

The pricing system proposed in Section 3.4, taken with the royalty system recommended in Section 3.6, and assuming average costs, were designed to yield average netbacks for British Columbia gas in 1985 of the order of:

(a) $0.90 per Mcf for post November 1973 gas; and
(b) $0.55 per Mcf for pre November 1973 gas.

with an average for all British Columbia production of some $0.73 per Mcf.

Details of the netback calculations are given in Appendix 5.

Recommendation

That by 1985 producer netbacks be increased toward target levels of $0.90 per Mcf for post November 1973 gas and $0.55 per Mcf for all other gas in order to stimulate drilling activity in the province to greater than 300 wells per year.

3.13 Provincial Consumer Subsidy or Rebate

Discussion The Study Group notes that retail gas prices are subsidized in British Columbia, Alberta and Saskatchewan. In Alberta the subsidy takes the form of a direct rebate while in the other two provinces the subsidy is implicit.

The Study Group has recommended an approach to wholesale pricing that will eliminate the implicit subsidy currently in place in British Columbia. The retail price implications of the Study Group's wholesale price recommendations are presented in detail in Appendix 8. A summary is as follows:

Table 6

ESTIMATED HYDRO RETAIL PRICES

Year	Retail Price[1] ($ per Mcf)	Change year to year ($ per Mcf)	Percentage Change (year to year)
current	4.66		
1983[2]	4.94	0.48	10.8%
1984	5.10	0.16	3.8%
1985	5.73	0.63	11.1%
1986	6.39	0.66	11.1%

[1] B.C. Hydro residential consumer.
[2] Price upon implementation assuming 7 percent increase in B.C. Hydro cost of service.

B.C. Hydro's retail rate increases are limited by provincial legislation, Rate Increase Restraint Act, S.B.C. 1982, c. 77, to 6 percent between September 1982 and September 1983, or approximately $0.28 per Mcf. However, the wholesale price recommendations of the Study Group would imply, in the absence

of a consumer subsidy, a $0.50 per Mcf increase. The Study Group believes there are two ways to accommodate this price increase restriction: first, restrict wholesale price increases or second, provide an explicit consumer rebate similar to that in Alberta.

The Study Group's view is that restricting wholesale price increases would constrain producer netbacks to levels below those necessary to revitalize the gas producing sector. This would effectively negate the positive effects of the foregoing financial recommendations. The second method, on the other hand, requires provincial funding. This would amount to $33.7 million at most for 1983 (calculated for a full 12 months).

The following shows the Study Group's estimate of the 1983 fiscal implications of the royalty, wholesale price and subsidy recommendations, assuming all recommendations are in place for the entire year and excluding the additional revenue which would accrue from bonus bids (for full details see Appendix 9).

Royalty Collection	$137.7 million
Less Subsidy	33.7 million
Net Revenue	$104.0 million

Beyond 1983, the need for a consumer subsidy will depend entirely on the government's view of the reasonableness of the retail price increases implied by the wholesale price recommendations. (See Table 6 and Appendix 8.) However, the Study Group believes that all subsidies should be explicit grants to consumers.

Recommendations

That an explicit consumer subsidy, in the form of a government grant or rebate to gas customers be introduced as necessary to ensure that consumer gas rate increases for 1983 remain within the guidelines of the Rate Increase Restraint Act, S.B.C. 1982, c. 77.

That, after 1983, if the government decides to continue consumer subsidies, they be made by explicit grant and not at the expense of the wholesale price.

That all subsidies be paid to the consumer either directly or through the distribution utility.

3.14 Provincial Consumer Price

Discussion The Study Group has observed that residential and commercial customers in the B.C. Hydro service area (Vancouver) pay a higher per unit cost than customers in Edmonton, Calgary or Regina. While the residential and commercial customers in the Inland service region (Prince George, Kamloops) pay a lower price than B.C. Hydro customers, they generally pay a higher price than customers in Edmonton, Calgary or Regina. The price of natural gas in British Columbia is however considerably less than the energy equivalent price of oil or electricity.

Recommendations

That the retail rates for natural gas continue to be determined by the BCUC at levels equal to the wholesale price specified in Section 3.4, plus the appropriate distributor cost of service. (The final consumer price would be the retail price less any subsidy.)

Appendix 1

Study Terms of Reference

Preamble The government of British Columbia uses natural gas as a key strategic resource which, through proper management, can make an important contribution toward the future health of the British Columbia economy. The government's policy is to ensure that British Columbia's natural gas resource will be developed to achieve the maximum benefit for the people of the province. In this regard, the government of British Columbia places great emphasis on:

a) stimulation and expansion of markets for British Columbia natural gas; and

b) stimulation of exploration and development in the petroleum and natural gas industry in British Columbia and the attendant benefits to the industry and the province as a whole.

It is the government's view that actions taken in pursuit of the foregoing objectives will enhance the benefits to British Columbians in terms of both direct revenue received by the Crown from the production and sale of the resource, and through the stimulation of employment opportunities flowing from the petroleum and natural gas sector.

As a vital step in achieving these objectives the Minister of Energy, Mines and Petroleum Resources directs that a study of all critical aspects of the marketing of natural gas produced in British Columbia be undertaken.

Terms of Reference The study is to cover the following:

1. A review of the policies, system, and procedures in British Columbia, Alberta and Saskatchewan, including the impact of external regulatory authorities, relating to the intra and extra provincial marketing of natural gas, including the sale by producers, the gathering, processing, and transportation of natural gas, and the resale of marketable natural gas to the wholesale market.

   This review should focus on the development of a marketing system whereby the Province of British Columbia could most effectively create and/or capture any and all opportunities to market natural gas for the maximum overall benefit of provincial residents.

   The review should assist in the ultimate definition of appropriate roles and relationships for institutions and entities involved in the British Columbia natural gas marketing system, both existing and new.

   The review will include, without restriction, an identification of aspects related to the disposition of petroleum and natural gas rights, the pricing of natural gas both in the field and to wholesale buyers and the present or any proposed system of royalties, which would be conducive to the objectives stated in the preamble, particularly the stimulation and expansion of markets for British Columbia natural gas.

2. The development of recommendations relating to the marketing of British Columbia natural gas and, in particular, the matters reviewed under item 1. above, to be provided in a report submitted to the Minister.

Appendix 2

Definitions

BCPC/Westcoast Basic Agreement

- a letter agreement, effective November 1, 1973 in which Westcoast assigned all its British Columbia gas purchase contracts to the BCPC. In return the BCPC agreed to supply Westcoast with British Columbia gas; Westcoast agreed to buy from BCPC all gas necessary to fulfill its existing contractual commitments.

Economic rent

- that amount in excess of the total cost, including a return to the producer, that is paid for a commodity.

Cost of service

- the cost of transporting and processing gas as calculated per regulatory practices.

Export flowback

- the incremental export revenue distributed to producers in proportion to their total production of marketable natural gas.

Federal/Alberta agreement (1981)

- Memorandum of Agreement between the federal government and the Alberta government relating to energy pricing and taxation, effective September 1, 1981.

Field gathering system

- includes the flow line system, the dehydration system and the field lateral which collects the raw gas from individual wells and transports it to a central point (i.e. processing plant or point of connection with a transmission lateral).

Future contracted gas
- gas which is obtained for the purpose of providing a service for which a new or revised contract will be required.

Gross field price
- wholesale price plus export flowback minus cost of service.

Marketable gas
- gas that has been processed.

Marketable gas transmission lines
- the main, or trunk pipelines which carry marketable gas.

Producer netbacks
- funds available to the producer to cover exploration and development costs and return on investment.

Raw gas
- gas that may have been dehydrated but not otherwise processed.

Straddle plants
- gas processing plants are located downstram of the raw gas processing plants(s) and are designed to recover additonal natural gas liquids from marketable gas.

Total field price
- gross field price plus revenue (after processing costs) of any by-products credited to the producer of raw gas.

Transmission laterals
- pipelines which carry raw or marketable gas from the field gathering point or the processing plant to a main transmission line.

Wholesale price

- the price at which gas is sold to domestic wholesale purchasers.

Appendix 3

Summary of Industry Responses

This is a summary of industry responses to Dr. Govier's request for opinions on the marketing of British Columbia natural gas. Responses to Dr. Govier's letter of October 14 (see Attachment 1) were received from 24 companies, associations and Crown agencies (listed in Attachment 2).

No attempt has been made to reproduce the views of all the companies on every topic covered. Rather, opinions are summarized under the following broad category headings taken from the Report: Disposition of Natural Gas Rights; Marketing Arrangements and Agency Roles; Market Development; Pricing and Tariffs; Royalties and Equivalent; Provincial Producer Incentives; Producer Netback; Provincial Consumer Rebate or Subsidy; and Provincial Consumer Price.

Disposition of Natural Gas Rights

According to industry respondents, the recent increases in rentals and work obligations under the Petroluem and Natural Gas Act have increased the possibility of petroleum and natural gas rights reverting to the Crown because drilling for natural gas cannot be economically justified at present. While the current surplus of natural gas persists, the respondents feel that recent increases in rentals and work requirements should be cancelled and consideration should be given to extending lease and permit expiry dates.

It was also suggested that permit posting configurations be relaxed so that corridor acreage could be posted in permit form and that, following a discovery, approved expenditure work credits could be made applicable for the reduction of lease rentals.

Marketing Arrangements and Agency Roles

Most respondents indicated that more innovative strategies for natural gas marketing were required. In general, it was recommended that the responsibility for marketing be given to those bearing the risk. Three basic alternatives were cited: direct producer marketing with Westcoast acting as a common carrier; marketing responsibility assigned to the BCPC; and Westcoast being given a greater incentive to increase sales and reduce costs by fixing its tariffs on the basis of a prospective test year.

Most respondents preferred 'direct producer marketing' since producers currently bear the greatest risks and have the most to gain from increased gas sales. Also, direct producer marketing would provide the government with a large, highly motivated sales force at minimal additional cost.

With the exception of the minor transportation role of the three major provincial utilities, the costs of service of gathering, processing and transportation of natural gas are under the jurisdiction of the National Energy Board through its regulation of Westcoast. It was suggested that the provincial government should have more input into the determination of these costs of service.

Several respondents felt Westcoast's monopoly on gathering and processing should be curtailed and producers should be allowed to gather and process their own gas. Also, natural gas liquids recovery should be encouraged.

Market Development

Respondents generally agreed that in the short term, the approach to market development should be to properly define the market for British Columbia natural gas in the Pacific Northwest by innovative

pricing arrangements and negotiated amendments to existing contracts. For example, export prices could be based on one price for firm gas and another for peaking gas. Also, effective take-or-pay arrangements could be introduced into Westcoast's GL-41 export contract. In addition, it was suggested that direct sales by any party to incremental export and potential large domestic customers should be allowed, and regulatory procedures should be conducted expeditiously for incremental short term exports. The general recommendations of the recently released Alberta government market development plans were supported.

A further possibility is to curtail the Pan-Alberta contract under which Alberta gas supplies the British Columbia export market. Also, British Columbia natural gas from the Northwest system could be used to displace Alberta gas supplying Pacific Gas Transmission from the Alberta Natural Gas system. The displaced Alberta gas could be shipped east to supply Texas Eastern.

While respondents noted that a substantial improvement in sales would be forthcoming if the Westcoast scheme to organize off-system sales to Texas Eastern and Transwestern comes to fruition, this was not felt to be the long term solution.

Some respondents indicated that the long term solution to the market problem would be found in future sales of LNG to Japan, the use of CNG as a motive fuel, and the construction of petrochemical and fertilizer plants on the west coast. Others believe the emphasis should be placed on the expansion of markets for British Columbia natural gas into the United States midwest and northeast. The latter option would, of course, require cooperation from the Alberta government and NOVA.

Pricing and Tariffs

The current export price is generally considered to be too high. Westcoast's United States customer under GL-41 - Northwest Pipeline Corporation - paid just $2.16 per Mcf for its supply of indigenous gas (45 percent of the total purchased) during 1981. The other 55 percent was Canadian gas at $4.94 per MMBTU making the average price $3.69 per Mcf. Although United States gas prices will increase with deregulation, the respondents state that price reductions on Canadian gas for export to the United States are required. Many pointed out that the United States required a flexible export pricing policy. It was suggested that export prices could vary by regional market and by sector within any one market area. One suggestion is that exporters should be able to offer price discounts on incremental export sales above a minimum annual volume for a two year trial period.

Federal action would be needed to reduce the export price and although British Columbia producers may accept a lower netback, there is a danger that price reductions are not in the government's or producer's best interests since residual fuel oil and hydro prices might track lower natural gas prices and still retain a competitive edge.

As mentioned previously, Westcoast could be given a greater incentive to market gas if its tariffs were fixed on a prospective test year basis. Also, tariffs could be reduced by a switch from normalized to flowthrough income tax accounting.

Royalties and Equivalent

Most respondents are in favour of a sliding scale royalty system to provide long term field price predictability. Royalties could be reduced for low productivity wells. However, it was pointed out that a royalty system could create inequities, given the

multitude of gross overriding royalty deals based on the current 'net of royalty' pricing system.

Provincial Producer Incentives

Three provincial producer incentive schemes were suggested:

- geophysical and drilling incentives with royalty-free periods;
- the elimination of provincial sales tax for selected exploration and development costs;
- a five year royalty-free holiday for drilling within a two year term on existing petroleum and natural gas rights, and within the initial term of new petroleum and natural gas agreements.

Producer Netbacks

The theme that ran through most responses was that netbacks should be predictable and based on a set relationship with wholesale prices. Predictability would be increased by a royalty system. However, the continuation of the current 'netback stabilization' approach was also suggested with new netbacks established each year to maintain a set relationship between netback and market value. There was also a general consensus that netbacks be competitive with those available in other jurisdictions.

Provincial Consumer Rebate or Subsidy

Two consumer rebate schemes were suggested. First, the domestic consumption of gas in high volume industrial applications could be encouraged through preferential pricing, especially during the early years of a plant's operation. Second, the BCUC could administer provincial rebates or subsidies during the period that wholesale rates were phased to commodity

value. These discounts would be phased out over a three to five year period.

Provincial Consumer Price

The consensus of the respondents is that wholesale prices should be set at or near 'commodity value' in order to give distributors maximum marketing flexibility to be competitive with alternative fuels in each market sector. Price adjustments should be automatic and continuous. In the industrial sector, this flexibility could be achieved by a range of rates, including hybrid firm-interruptible contracts. No respondents explicitly stated by whom wholesale pricing should be regulated.

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Attachment 1

October 14, 1982

Dear

You are probably aware of the announcement October 7, 1982 by Deputy Minister Roy Illing of the appointment by the Honourable Brian Smith, Minister, Energy Mines and Petroleum Resources, of a study group on the marketing of B.C. natural gas. The study group includes Mr. A.G.T. Weaver, Mr. D.H. Horswill, Mr. M.M. Moseley and myself as Chairman. The terms of reference for the study are attached. You will note that the study is to cover a wide range of topics including the disposition of petroleum and natural gas rights, the gathering, processing and transportation of natural gas, the pricing of natural gas, royalties, and the roles and relationships of the institutions and entities involved.

The study is being carried out with the help of Ministry staff and outside consultants. No public hearings or meetings are contemplated nor are any formal submissions being requested. The study group, however, would appreciate receiving by a simple letter, any opinions that (insert company name) may wish to convey to it on any matter within the terms of reference provided this could be received by the end of October. May I stress that the group is not soliciting elaborate submissions but rather one, two or three page letters, or point-form documents outlining your views respecting the matters under consideration.

Any response you may make to this request will be kept within the working papers of the study group and not disclosed to others, although, naturally, the study group would anticipate that some of the views received would find their way into its recommendations.

. . . 2

This letter is being addressed to those shown on the attached list with the individually named producers being arbitrarily selected as the ten largest in terms of 1981 B.C. natural gas production.

Yours sincerely,

G.W. Govier
Chairman
Study Group
on the Marketing of B.C. Gas

Encl.

cc: Mr. Roy Illing

bcc: Mr. M.M. Moseley
Mr. A.G.T. Weaver
Mr. Doug Horswill
Mr. Campbell Watkins

Attachment 2

Respondents

Amoco Canada Petroleum Company Ltd.
BP Exploration Canada Limited
British Columbia Hydro and Power Authority
British Columbia Petroleum Corporation
Canadian Hunter Exploration Ltd.
Canadian Petroleum Association
Chevron Standard Limited
Czar Resources Ltd.
Dome Petroleum Limited
Esso Resources Canada Limited
ICG Utilities (Plains-Western) Ltd.
Independent Petroleum Association of Canada
KannGaz Producers Ltd.
Mobil Oil Canada Ltd.
Northland Utilities (B.C.) Limited
Oakwood Petroleums Ltd.
Ocelot Industries Ltd.
Pacific Northern Gas Ltd.
Petro-Canada
Quintana Explorations Canada Ltd.
Texaco Canada Resources Ltd.
Union Oil Company of Canada Limited
Wainoco Oil and Gas Limited
Westcoast Transmission Company Limited

Appendix 4

List of Top British Columbia Gas Producers

Gas Production by Operator
($10^6 m^3$)

Company	1981 (rank)	1980	1979
Petro-Canada	2,764.6 (1)	2,414.2 (1)	4,028.4 (1))
Mobil[1]	870.0 (2)	1,110.8 (2)	972.2 (2
BP[2]	415.2 (3)	-	-
Dome	371.2 (4)	450.3 (3)	487.7 (5)
Amoco	367.6 (5)	447.2 (4)	639.0 (3)
Czar	265.4 (6)	271.5 (7)	282.2 (8)
Texaco	258.3 (7)	343.9 (6)	394.4 (6)
Wainoco	254.7 (8)	397.6 (5)	491.0 (4)
Chevron	224.7 (9)	225.2 (10)	273.8 (9)
Esso	216.6 (10)	257.5 (9)	227.6 (12)
Canterra (CDC)	194.7 (11)	189.9 (11)	247.5 (11)
Quintana	187.2 (12)	267.1 (8)	318.2 (7)
Placid	185.6 (13)	161.1 (12)	269.0 (10)
Cdn. Reserve	114.3 (14)	144.7 (13)	158.0 (14)
Union Oil	94.5 (15)		

[1] Mobil frequently serves as operator for operations shared with Texaco, Shell and Gulf.

[2] BP: Appearance in 1981 in top 15 accounted for by connection of Bullmoose and Sukunka fields.

Appendix 5

Netbacks and Equivalent Netbacks

In Section 2.12 the Study Group introduced and defined the concept of netbacks and equivalent netbacks. Section 2.12 also provided estimates of the netbacks and equivalent netbacks. The first part of this appendix sets out the calculations that were undertaken in deriving those estimates. The second part of this appendix sets out the new netbacks available under the proposed royalty system for British Columbia. Part 2 of this appendix is included here to allow for ease of comparison. It should be studied, however, only after Sections 3.6 and 3.12 have been read.

A. Derivation of Current Netbacks and Equivalent Netbacks

i) British Columbia

Calculation of the 1982 Average B.C. Raw Gas Netback

($/Mcf)

	New Gas	Old Gas	Note #
Net Field Price	1.674	1.314	1.
Average Liquids Revenue	0.010	0.010	2.
Total Revenue	1.684	1.324	
less: Field Operating Costs	0.170	0.170	3.
Federal Income Tax	0.544	0.544	4.
PGRT	0.211	0.211	5.
PGRT Credit	(0.020)	(0.020)	6.
Provincial Income Tax	.242	.185	7.
gives: Producer Netback	.537	.234	

Notes:

1. The net field price shown is based on an MEMPR estimate of the average 1982 fair market value of $2.08 per Mcf. The net field prices, from the formulas are:

   New Gas 1.67 + .48 (2.08 - 2.55) + .23 = 1.674
   Old Gas 1.32 + .48 (2.08 - 2.55) + .22 = 1.314

2. The average liquids revenue is based on the 12.5 percent of liquids revenue that BCPC passes on to producers. Given an estimated total of $20 million for liquids revenue, 12.5 percent is $2.5 million. This is spread over total gas production giving approximately 1¢ per Mcf average.

3. These costs are the strict cash out-of-pocket expenses necessary to get gas into the Westcoast gathering system. The value given here represents a number estimated by the BCUC in 1980 ($.14 per Mcf based on submissions to their field price inquiry) which was inflated to arrive at figure.

4. The federal income tax for a fully taxable producer can be calculated as follows:

Deemed Field Revenues	2.090	- fair market value plus average liquids revenue
Less Field Operating Costs	.170	
Net Price	1.920	
Less 25 Percent Resource Allowance	.480	
Taxable Base	1.440	

Fed. Tax = .378 x taxable base = .378 x 1.440 = .544

5. The PGRT is calculated on the same taxable base as federal income tax above at 14.67 percent.

   PGRT = .1467 x taxable base = .1467 x 1.440 = 0.211

6. The federal government currently allows an annual credit of up to $250,000 against the PGRT liability of a corporation. This credit has been calculated by Dome to be worth about $.02 per Mcf on average.

7. The provincial corporate income tax, for a fully taxable producer, is composed of two parts and may be calculated as follows:

   (i) Gross tax is 16 percent of the taxable base shown in 4. above;
   Gross tax = .16 x taxable base = .230

   (ii) Tax rebate is 16 percent of the fair market value less the net field price less the 25 percent resource allowance as in 4. above;
   New Gas .16 x (2.08 - 1.674 - .480) = - 0.012
   Old Gas .16 x (2.08 - 1.314- .480) = 0.046

   (iii) Total tax is the gross tax less the rebate or;
   New Gas .230 - (-0.012) = 0.242
   Old Gas .230 - 0.045 = 0.185

ii) Alberta

Calculation of the 1982 Producer Netback (at full taxes) in Alberta with a Marketable Gas Price of $2.80 per Mcf

	$ per Mcf		
	Old Gas	New Gas	Note
Wellhead Revenues	3.725	3.725	1.
Field Operating Costs	0.170	0.170	2.
Processing Costs	0.480	0.480	3.
Total Royalties Payable	1.253	1.052	4.
PGRT	0.338	0.338	5.
PGRT Credit	(0.020)	(0.020)	6.
Federal Corporate Tax	0.872	0.872	7.
Provincial Corporate Tax	0.200	0.223	8.
Netback before Incentives	0.432	0.610	
Incentives:			
Exploratory Programs	-	0.06	
Average Long Term Royalty Tax Credit	0.07	0.07	9.
Average Low Productivity Well Adjustment	0.08	0.08	10.
Total Equivalent Netbacks	0.58	0.82	

Notes:

1. Total revenues include marketable gas and gas by-products. The by-product revenues as a percent of marketable gas revenues are: propane 7.2 percent, butane 6.2 percent, pentanes plus 13.0 percent, sulphur 6.6 percent. These percentages were estimated using data from the ERCB's monthly statistics for January, February, and March 1982. The revenues used were:

Marketable Gas	2.800
Propane	0.202
Butane	0.174
Pentanes Plus	0.364
Sulphur	0.185
	3.725

2. Field operating costs were assumed to be the same as in British Columbia. There is some evidence to suggest that these costs should be lower in Alberta than in British Columbia, but there is a lack of factual material proving this.

3. Processing costs used are the estimated value of the average gas cost allowance for 1981, inflated to a 1982 value at approximately 12 percent. The full gas cost allowance is used rather than just the operating cost portion, as it is the return to exploration and development investment that the netback should represent and not investment in the gas plant (to make it comparable to the netback calculated for British Columbia).

4. Royalties payable may be calculated as follows. First gross royalties are calculated according to Alberta regulations. Given the above revenues, gross royalties will be:

	Old	New
Marketable Gas	1.145	0.915
Propane	0.061	0.061
Butane	0.052	0.052
Pentanes Plus	0.149	0.149
Sulphur	0.031	0.031
Total	1.438	1.208

This gives an average royalty rate on old gas of .3860 (i.e. 1.438 ÷ 3.725) and an average royalty rate on new gas of .3243 (i.e. 1.208 ÷ 3.725). The

total royalties payable are then calculated according to the formula

$$TRP = ARR \times (TR - GCA)$$

where TRP = Total Royalties Payable
ARR = Average Royalty Rate
TR = Total Revenue
GCA = Gas Cost Allowance

Using this, the total royalties payable on old gas are 1.253, and on new gas are 1.052.

5. The PGRT on both old and new gas may be calculated as follows:

Total Revenues	3.725
Less Operating and Processing Costs	0.650
Net Price	3.075
Less 25 percent Resource Allowance	0.769
Taxable Base	2.306

The PGRT is 14.67 percent of the taxable base or 0.338.

6. The PGRT credit is an annual deduction of up to $250,000 against the PGRT liabilities of a company. Dome estimates that this credit should be worth about 2¢ per Mcf on average.

7. For a fully taxable producer, federal corporate income tax is 37.8 percent (i.e. 36 percent plus the 5 percent surtax) of the taxable base as shown in 5. above, or 1.872.

8. Provincial corporate tax for a fully taxable producer may be calculated:

	Old	New
Total Revenues	3.725	3.725
Less Operating and Processing Costs	0.650	0.650
Less Total Royalties Payable	1.253	1.052
Taxable Base	1.822	2.023

where the tax rate on the base is 11 percent giving taxes payable on old gas of $.200 and on new gas of 0.223.

9. The royalty tax credit has been raised significantly for 1982 and 1983, but is intended to return to its previous levels for 1984 and thereafter. Adhering to the policy of matching long term incentives with netbacks, but not short term incentives, the royalty tax credit for gas is estimated to be worth about $170 million or $.07 per Mcf.

10. Alberta provides a royalty reduction for wells producing under 600 Mcf per day. The average value of this reduction is estimated to be about $0.08 per Mcf.

iii) Saskatchewan

Saskatchewan Natural Gas Netbacks
Large Producer Netbacks
($ per Mcf)

	1982	
	Old	New
Fieldgate Price	0.46	0.75
Operating Costs	0.25	0.25
Crown Royalty	0.02	0.02
PGRT	0.02	0.06
Before Tax Netback	0.17	0.42
Full Taxes:		
Federal	0.06	0.14
Provincial	0.03	0.17
Netback After Tax	0.08	0.21

B. Derivation of Netbacks Under Proposed British Columbia Royalty System

1983 British Columbia Gas Netback Estimates
(at full taxes $/Mcf)

	Pre November 1973*	Post November 1973	Note #
Total Field Price	2.650	2.650	1.
Field Operating Costs	.190	.190	2.
Royalty	.756	.496	3.
PGRT	.295	.295	4.
PGRT Credit	(.020)	(.020)	5.
Federal Corporate Tax	.681	.681	6.
Provincial Corporate Tax	.273	.314	7.
Netback	.475	.693	

* November/73 is date currently used to distinguish 'old' and 'new' gas.

Notes:

1. The total field price of $2.650 per Mcf is based on implementation of the recommendation to make the average wholesale price equal to the Alberta border price in 1983.

2. These costs are the strict cash out-of-pocket expenses necessary to get gas into the Westcoast gathering system. The value given here represents a number estimated by the BCUC in 1980 ($.14 per Mcf based on submissions to their field price inquiry) which was inflated to arrive at a 1983 figure.

3. Royalty payable is based on the proposed royalty formula and cost related factors. The applicable royalty rates are 28 percent for pre November 1973 gas, and 18 percent for post November 1973 gas, derived from the average values given in Appendix 7 and adjusted for price.

4. The PGRT on all gas may be calculated as follows:

	Total Field Price	2.650
Less:	Operating Costs	.190
	Net Price	2.460
Less:	25% Resource Allowance	.615
	Taxable Base	1.845

The PGRT is 16% of the taxable base, or .295.

5. The federal government currently allows an annual credit of up to $250,000 against the PGRT liability of a corporation. This credit has been calculated by Dome to be worth about $.02 per Mcf on average.

6. For a fully taxable producer, federal corporate income tax is 36.9 percent (i.e. 36 percent plus the 2.5 percent surtax) of the taxable base as shown in 4. above, or 0.681.

7. Provincial corporate tax for a fully taxable producer may be calculated:

	Pre November 1973	Post November 1973
Total Field Price	2.650	2.650
Less: Operating Costs	.190	.190
Less: Royalties	.756	.496
Taxable Base	1.704	1.964
Taxes Payable at 16 Percent	.273	.314

Appendix 6

Comparative Residential Retail Natural Gas Prices

Presented below, for purposes of comparison, are current residential natural gas retail prices for major markets across Canada and the United States. (All figures in $ Canadian, U.S. $1 = Cdn. $1.20.)

CITY	$/Mcf
Vancouver	$4.66
Edmonton	3.90
Regina	3.72
Calgary	4.20
Toronto	6.59
Seattle	6.37
San Diego	5.69
Chicago	5.99
Boston	10.32
Oklahoma City	4.86
San Francisco	5.44
Los Angeles	5.88

Appendix 7

Royalties

The royalty system outlined in this appendix has two primary objectives. First, the system will provide predictability to industry, an objective long sought by British Columbia's gas producers. Second, the system will provide a netback to British Columbia's gas producers comparable to that realized by Alberta's producers, an objective also sought by industry for a considerable time (see Appendix 5: Netbacks and Equivalent Netbacks).

The first objective is realized through the very nature of a royalty system assuming permanence. The second objective is realized via the royalty rates applied.

This appendix then sets out the method by which the royalty rates in the proposed system are to be developed and applied.

In Section 3.6 the Study Group introduced its concept of R% = f (CRF's, PF)

where R% = Royalty Rate, percent
CRF's = Cost Related Factors
PF = Price Related Factor

Also it identified
1. time of first production or 'age';
2. location and topography;
3. well depth; and
4. production rate

as the most important factors affecting the unit cost of developing natural gas in British Columbia - i.e. as the CRF's. The factors in the formula are now discussed in more detail.

Cost Related Factors (CRF's)

A relatively simple manner in which subjective allowance may be made for the variation in unit costs with these CRF's involves assigning 'royalty elements' to each of several levels of the factors and then adding the elements to obtain a total, for a particular set of factors. With the assigned elements suitably chosen and inversely related to cost, their total will be directly related to the maximum royalty rate which would be appropriate for a particular set of the CRF's.

The Study Group has developed the following CRF table which it considers to be applicable to all gas produced in British Columbia whether it is presently designated as 'old gas' or 'new gas'.

Age		Location		Depth		Production	
Years	Elem.	Desig.	Elem.	Feet	Elem.	MMcf/month	Elem.
< 4	4	D	4	> 12,000	4	< 10	0
> 4	6	C	5	< 12,000	6	< 30	2
> 8	8	B	6	< 9,000	8	< 60	4
>12	20	A	7	< 5,000	10	> 60	7

As an example, the maximum royalty rate ($R\%_{max}$), unadjusted for price, for a well having produced 5 years, from location A at depth 11,000 feet and at 24 MMcf in the month would be arrived at by adding the elements as follows:

for age	6
for location	7
for depth	6
for production	2
Total	21 = maximum royalty ($R\%_{max}$)

Similarly the $R\%_{max}$ for any other set of the CRF's may be determined. The elements

illustrated above lead to a theoretical range in the value of $R\%_{max}$ of 12 percent for the 'newest, highest cost gas' to 44 percent for the 'oldest, lowest cost gas'. (The range in practice is estimated to be somewhat narrower, from 14 percent to 40 percent.) Definitions of the four CRF's are shown in Attachment A(1).

As the above procedure is proposed for application to all gas production in the province the designation of gas as 'old' and 'new' will no longer be required. However, the royalty elements assigned to the age factor are designed to retain the concept of 'vintaging' but on a progressive basis. For example, the value of $R\%_{max}$ in the above illustration will increase from 21 percent to 23 percent and then to 35 percent as the producing life of the well reaches 8 years and 12 years respectively. Conversely, the production factor will allow for a reduction in royalty rate as the producing capability of the well declines.

Price Related Factor

Turning to the price factor (PF) the Study Group endorses the increase in R% with increasing price, eventually reaching $R\%_{max}$ at a sufficiently high price. Moreover, it believes that the rate which the R% should increase with price must diminish as higher prices are reached - otherwise the rate would eventually become 100 percent. The simplest mathematical relationship which has this derived characteristic is

$$R\% = R\%_{max} (1 - e^{-kp})$$

where k = constant
p = total field price

The constant k determines the rate at which R% increases toward $R\%_{max}$ with increasing price. It may be set by fixing, on the basis of judgement, the ratio of R% to $R\%_{max}$ at any given price. The Study Group considers it reasonable to set the value of

R% at 0.90 $R\%_{max}$ when p = $5.00 per Mcf. On this basis the value of k is 0.46052 and for a total field price (p) of $3.50 per Mcf, the royalty rate applicable to the example given in the previous section is obtained by multiplying the values of $R\%_{max}$ by 0.80.

The ratio of $R\%/R\%_{max}$, is dependent only on the total field price, is expressed graphically in Attachment B.

Results

The results of applying the above royalty system to gas produced in 1985 are given below. The estimates of producer netback are based on a value of $3.50/Mcf for average total field price during that year.

	*Pre-November 1973	Post-November 1973
Theoretical Range of Royalty R%	22 - 35%	10 - 26%
Practical Range of Royalty R%	31 - 34%	11 - 26%
Average Royalty	32%	21%
Theoretical Range of Netback	$.84-.47/Mcf	$1.22-.75/Mcf
Practical Range of Netback	$.59-.50/Mcf	$1.18-.75/Mcf
Average Netback	$.55/Mcf	$.90/Mcf

* November 1973 is the date currently used to distinguish 'old' and 'new' gas.

The Study Group believes that the level and predictability of the ranges and average values of royalty rates and producer netbacks, as exemplified above, will be significant factors in meeting the economic requirements for drilling activity in British Columbia to exceed 300 wells per year. Another important factor, of course, is the prospect of a near term market for newly developed gas.

Implementation

In Section 3.6 it was indicated that royalties on 'future contracted gas', as that term is used in Section 3.3, would be paid by the producer directly to the Mineral Revenue Branch (MRB) of the Ministry. This would also apply to gas sold to the BCPC under existing contracts if these contracts were suitably amended. In cases where such amendments did not take place and the BCPC continues to pay revenues to producers net of royalty a procedure along the lines of the following could be adopted.

1. Producers submit to the MRB their monthly estimates of royalty on the standard form.

2. After confirmation, the MRB informs the BCPC of the royalty applicable to each distribution point.

3. The BCPC makes payment to the producers based on total field price minus royalty, from funds received from Westcoast.

4. The BCPC remits the royalty collected in this manner to the MRB of the Ministry.

In order to implement this procedure the definition of Residue Gas Price in BCPC's current gas purchase contracts would have to be changed to reflect the revised pricing system.

Attachment A(1)

Definitions for Proposed Royalty System

1. Depth - average depth of the base of the net pay in the pool from which the well produces.

2. Location - the location of the pool from which the well produces as defined in the attached plan A(2); if the pool overlaps two areas the more 'expensive' area is assigned to the whole pool.

3. Regular Production - production from a well into a pipeline system for commercial sale.

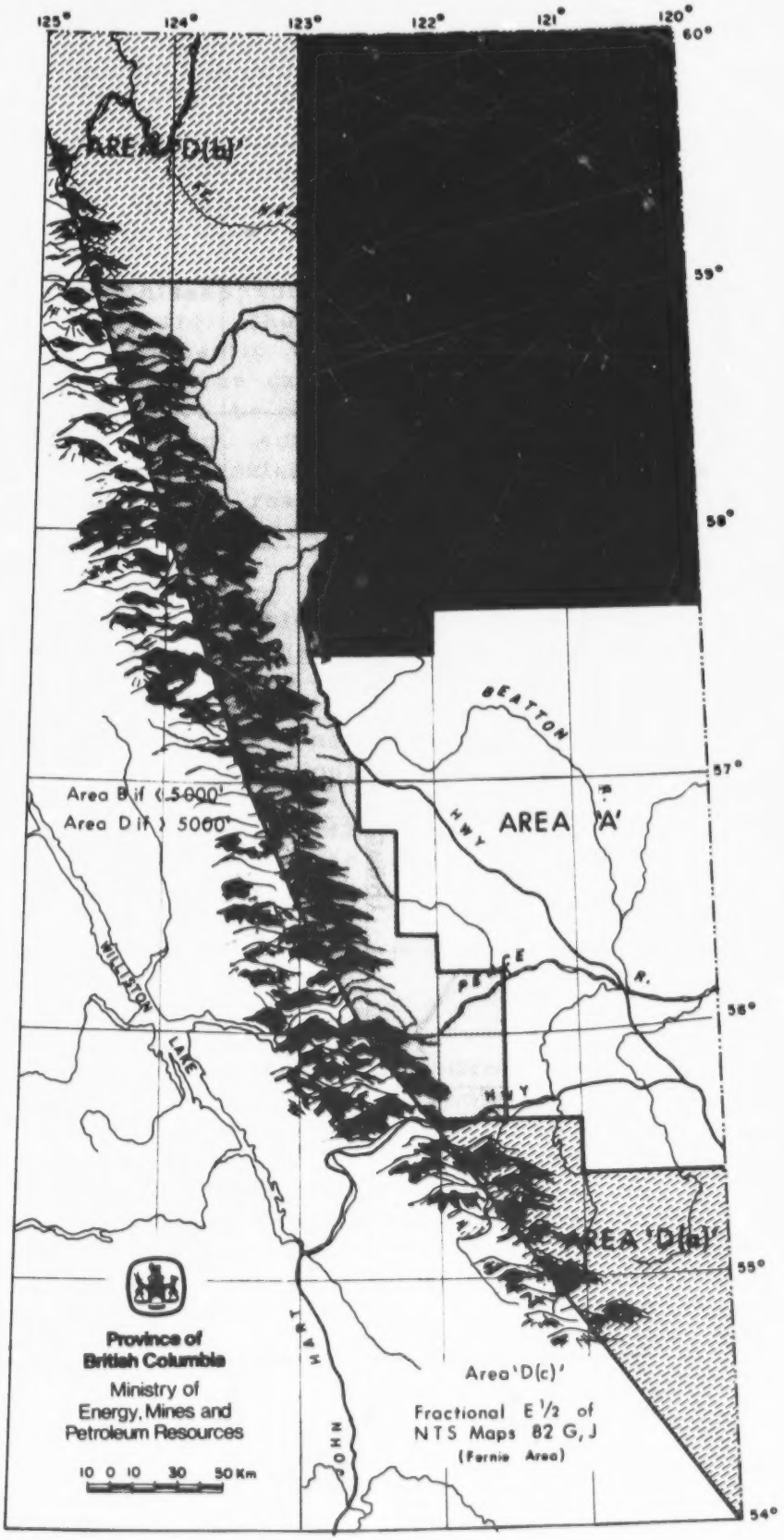
4. Age - the calendar time from the date when a well producing gas first went on to regular production.

5. Production Rate - the amount of raw gas which is produced in a month from a well, or allocated to a spacing area.

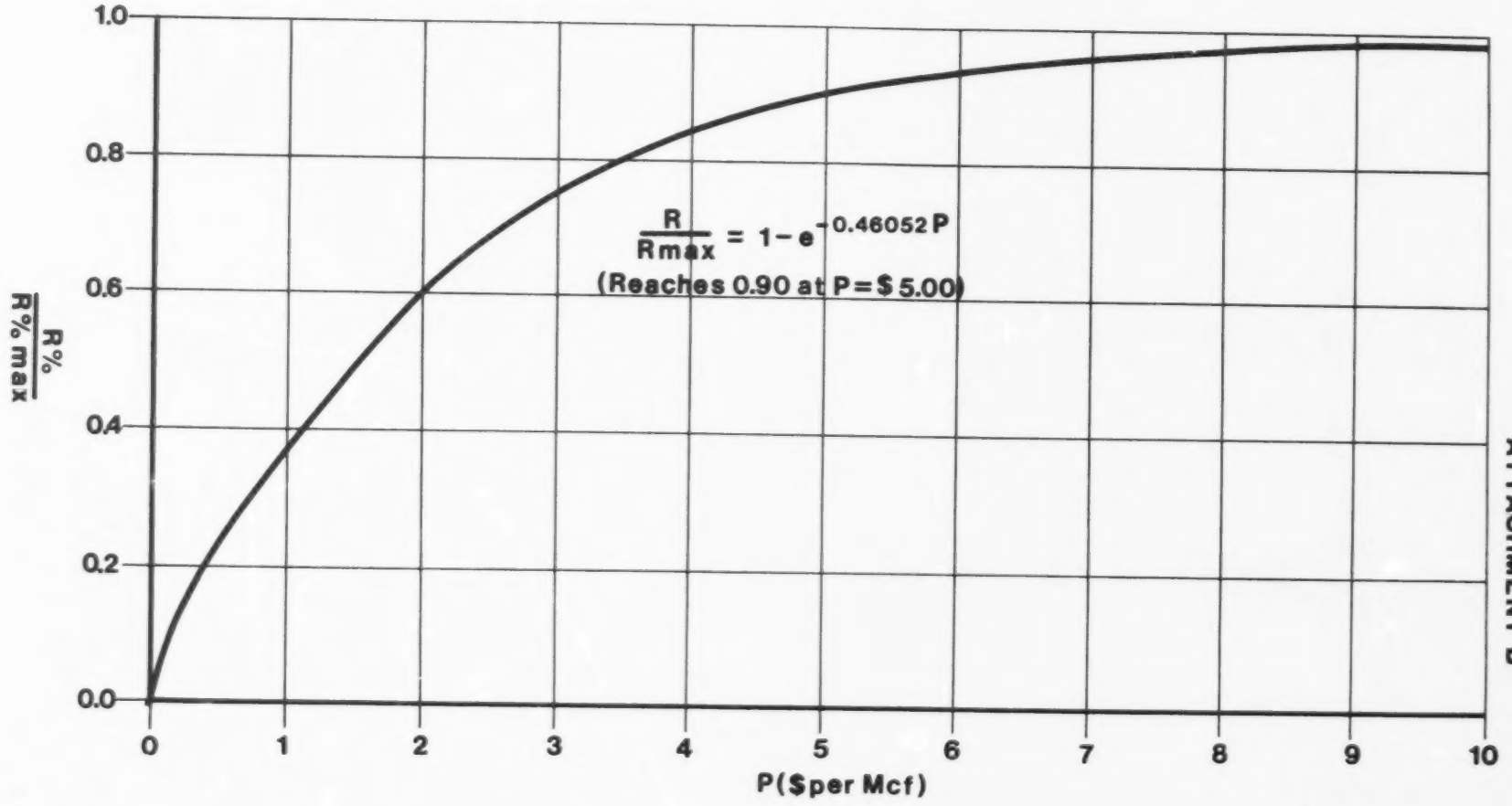
6. Price - total field price (including export flowback) published for the month.

Definition of LOCATION

Attachment A (2)



ROYALTY - PRICE RELATIONSHIP



ATTACHMENT B

Appendix 8

Retail Price Implications of the Wholesale Price Recommendations

This appendix presents the retail prices that would result from the adoption of the recommendations made as to domestic wholesale pricing in Section 3.4. Included within the calculations is an allowance for the rate increases to be allowed under the province's Rate Increase Restraint Act (although the Act is limited to B.C. Hydro's gas sales, the need to have equality across the province will result in all other provincial gas utilities being subjected to a similar limit).

Retail Price Implications of the Wholesale Price Recommendations for B.C. Hydro ($/Mcf)

Year	Wholesale Price	NGGTL & COSC	Fuel Cost	Distribution Margin	Retail Price	Subsidize Price
1982	2.02	0.64	.17	1.63	4.46	4.46
1983	2.73	0.30	.18	1.75	4.96	4.74
1984	3.08	--	.18	1.84	5.10	--
1985	3.58	--	.21	1.94	5.73	--
1986	4.07	--	.24	2.05	6.37	--

Notes:

1. In Section 3.4 the Study Group recommended that increases in the average wholesale price of natural gas be phased in so that they contribute to producer netbacks achieving the levels recommended in Section 3.12. This objective has been achieved by having the average wholesale price set equal to the Alberta border price in the years 1983 and 1984 and then having the average wholesale price move, in equal steps, to equal 65 percent of the energy equivalent cost of crude oil at the Vancouver refinery gate by 1990.

2. Estimates of Natural Gas and Gas Liquids Tax and Canadian Ownership Surcharge provided by Ministry of Energy, Mines and Petroleum Resources staff.

3. Estimates of B.C. Hydro fuel cost provided by Ministry staff.

4. Distribution margin is for an average consumption level of 115 Mcf per year. It is increased at the projected rate of inflation.

5. Retail price equal to sum of wholesale price, NGGLT, COSC, fuel cost and distribution margin.

6. Subsidized price equal to 1982 price plus percentage increase allowed under Rate Increase Restraint Act: 6 percent in 1983.

7. Alberta border price is based on scheduled in Canada/Alberta Pricing Agreement, 1981; annual average is presented.

Appendix 9

Fiscal Implications of Recommendations

This appendix summarizes the financial implications on the provincial Treasury if the Study Group's recommendations on the proposed royalty system, wholesale pricing and retail pricing are adopted. The numbers presented here reflect the Ministry's current estimate of domestic and export volumes for the years provided. It should be noted that these estimates produce a total field price only slightly below the 1985 target of $3.50/Mcf.

Impact on Provincial Treasury of Adopting Recommendations [1,2]
(millions of current dollars)

	Total Royalty	Subsidy	Revenue to Treasury
1983	$137.7	$33.7[3]	$104.0
1984	166.0	-	166.0
1985	188.9	-	188.9
1986	240.4	-	240.4
1987	321.6	-	312.6

Notes:

1. For purposes of comparison the corresponding revenues have been calculated for 1983 assuming no change in the current system (procedure or values). The resulting figures would be: Royalty (implicit) $190 million; Subsidy (implicit) $70 million; and Revenue to Provincial Treasury $120 million. Because of the subjective nature of the present system no attempt has been made to forecast beyond 1983 on the basis of the existing system.

Notes continued:

2. Assumptions used in calculations:

Year	Average Wholesale Price ($/Mcf)	Total Field Price ($/Mcf)	Total Sales* (Bcf)		Average Royalty Percent
			Domestic	Export	
1983	$2.65	$2.73	146	65	24
1984	3.15	3.02	149	65	25
1985	3.65	3.38	154	67	26
1986	4.15	3.82	167	69	26
1987	4.67	4.27	182	102	26

* 1987 export volumes include 30 Bcf for Western LNG

3. Subsidy as necessitated by Rate Increase Restraint Act is 22¢ per Mcf in 1983.

Appendix 10

List of Documents on File

1. Letter from Dr. G. Govier to Industry

2. Industry Responses to Letter

3. Background Papers:

   (1) British Columbia Natural Gas Policies Systems and Procedures
   (2) Alberta Natural Gas Policies, Systems and Procedures
   (3) Saskatchewan Natural Gas Policies, Systems and Procedures

Province of British Columbia

NEWS RELEASE

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

FOR IMMEDIATE RELEASE

1983:34

September 15, 1983

NEW DEAL FOR B.C. NATURAL GAS

Victoria, B.C. - The government of British Columbia will reduce its regulation of the province's natural gas industry and give the private sector a chance to operate more freely.

This is the overriding theme of a new deal for the industry announced by Energy Minister Stephen Rogers as he released a major report on the marketing of B.C. natural gas. The government will move quickly to implement many of the report's recommendations, he said.

"With these policies we are setting in place a system that will encourage exploration and development, help find new markets for B.C. gas, enhance energy security for the province, attract new industries, and set fair prices for both producers and consumers," Rogers said.

"These initiatives are designed to assist the ailing gas industry and, in the process, play a significant role in the provincial government's strategy of stimulating economic recovery through the private sector."

For the first time, private producers will be allowed to sell gas directly to eligible buyers without having the B.C. Petroleum Corporation act as middleman. This applies only to future-contracted gas and will eliminate the effective monopoly BCPC holds on the purchase and sale of natural gas.

At the same time, the private sector will be encouraged to seek out new customers, both domestic and foreign.

In future, producers will be permitted to make new sales directly to any eligible buyer. For the present, the government has authorized them to negotiate new sales to: the U.S. export market, the liquified natural gas (LNG) plant proposed by Dome Petroleum near Prince Rupert, and the ammonia/urea fertilizer plant proposed in conjunction with a Vancouver Island gas pipeline.

Producers now will be able to move aggressively to develop markets for their gas, Rogers said. As for the LNG and fertilizer plant proposals:

"The prospect of direct deals with producers provides some flexibility of pricing not available under the present system. It should facilitate the arranging of gas supply from B.C. for the LNG project (half the gas for this project will come from Alberta), and will improve the chances of an ammonia/urea project proceeding."

Another major thrust of the new policy initiative is the establishment of a rational pricing structure for field and wholesale prices, to provide a large measure of much-needed predictability for producers, utilities and industry. In addition, netbacks to producers will be increased in order to stimulate drilling activity in the province.

"In this way we encourage producers to open up new gas supply, and we stimulate the development of industrial projects that use natural gas. Meanwhile, within our stable pricing framework, we give the gas industry far greater freedom and flexibility than it enjoyed in the past," Rogers said.

.../3

The minister noted that a key element of the new policy is "to maintain residential gas prices for British Columbians at levels well below those paid by most other Canadians."

Other major components of the government's gas strategy are:

- to protect current contractual obligations and arrangements with BCPC;
- to allow producers to build and/or own their own gas transmission and/or processing facilities; and
- to collect government revenues directly, through a royalty applied to all gas produced in the province, rather than through the present indefinite mechanism via BCPC. As an incentive to producers, minimum royalty will be charged on new wells.

A Report on the Marketing of British Columbia's Natural Gas makes 46 recommendations in all, and the government rejects only two of them:

- it refuses a proposed two-year royalty holiday for new wells because that was not considered as effective an incentive as other measures already approved; and
- it turns down, for the present, the suggestion that BCPC be allowed to develop its own future markets and sell gas directly.

The minister announced he is seeking written comment from industry on several issues raised by the report and by the government's policy decisions. They include:

.../4

- the question of BCPC marketing gas directly;
- the criteria to be applied to direct industrial sales by producers;
- various aspects of Westcoast's role as a gas purchaser, carrier, processor and marketer; and
- the development of underground storage capacity for natural gas in the Fraser Valley.

"The government wants this input quickly, so it can act quickly to implement the report's recommendations," Rogers said. "We expect to complete the job of restructuring the natural gas marketing system within a year."

However the minister added that B.C.'s gas industry will not be revitalized overnight.

"It will be some time before British Columbia starts to get the full benefit of the decisions we are making today," he said. "We implement good policies now; the returns will be in the future."

The report on which the government's new gas policy initiative is based, is the work of a study group headed by Dr. George Govier, a prominent Calgary consultant and internationally recognized expert in the field of petroleum and natural gas.

-30-

For further information:
J.J. Banky
Director of Communications
(604) 387-5178

A Report on the Marketing of British Columbia's Natural Gas

BACKGROUNDER

1. In 1979, OPEC doubled the price of oil and the world energy crisis moved into high gear.

2. In February, 1980, then Energy Minister Bob McClelland issued a paper entitled An Energy Secure British Columbia: the Challenge and the Opportunity. The document outlined a policy aimed at giving this province energy security in a suddenly insecure world.

   Three main elements of this policy were:
   - to manage the province's energy resources responsibly;
   - to make the most of opportunities for industrial development; and
   - to set energy prices that would encourage both conservation and adequate energy development, while at the same time protecting the needs of consumers.

   Much has changed since that statement was issued, but the objectives of the government remain essentially the same.

   Another thing that hasn't changed: natural gas was identified then as the most appropriate energy resource for development. It still is.

3. Also in 1980, the federal government brought in its controversial National Energy Program (NEP), which was to provide the framework for a national strategy of energy security and development. Instead it precipitated a period of extreme uncertainty within the country which, coupled with the rapidly changing circumstances of the international energy scene, made the B.C. government's job of setting energy policy that much more difficult.

.../2

4. In July, 1981, the provincial government released the Natural Gas Price Inquiry Report of the B.C. Utilities Commission. This led to pricing changes:
   - The field price of gas was raised, to encourage continued development of the resource.
   - The wholesale price was increased, moving retail prices to a level that more closely reflected the proper value of the resource, thus encouraging wiser use.

   In a separate move, the province initiated the Natural Gas Allocation Process and advertised throughout the world, inviting proposals for petrochemical plants, pipeline projects and liquefied natural gas (LNG) projects.

5. The results of the National Energy Program have been well documented. In combination with the recession, it has produced a drastic decline in resource revenues in this province, both for government and for producers. Drilling activity fell from 395 wells in 1979 to a projected 50 to 60 wells in 1983. Our gas exports fell from 167 billion cubic feet (Bcf) in 1979 to a projected 45 Bcf this year.

6. Throughout this difficult period, the government continued its efforts to stabilize and revive B.C.'s ailing natural gas industry, while delicately balancing the needs of domestic consumers. During 1982:
   - The Govier report on British Columbia's Requirements of Natural Gas and Natural Gas Liquids identified the amount of natural gas that would be surplus to B.C.'s normal domestic and export requirement over the next 30 years.
   - The Natural Gas Allocation Process was concluded, with an LNG plant and a fertilizer plant selected as priority projects, in addition to continuing the commitments to serve traditional U.S. markets.
   - The government enunciated a policy targeting northern and interior B.C. as the area for industrial development based on natural gas.
   - The government also financed gas pipeline extensions through its Gas Extension Assistance Program.
   - The use of compressed natural gas (CNG) as an alternate transportation fuel was encouraged through conversion grants, training programs for mechanics and market promotion.

.../3

7. In 1983:
   - The R.J. Abercrombie report Natural Gas Supply to Vancouver Island demonstrated the technical feasibility, cost-effectiveness and economic value of a natural gas pipeline to Vancouver Island. The B.C. Utilities Commission is now in the process of deciding who will build it.
   - An ammonia-urea fertilizer plant is proposed in conjunction with the Vancouver Island gas pipeline.
   - The Western LNG proposal is before the National Energy Board.
   - Most recently, in an effort to solve producers' cash-flow problems and encourage new exploration and development, the government increased the field price and subsequently the wholesale price of natural gas, effective August 1.

8. In November, 1982, the Ministry of Energy, Mines and Petroleum Resources commissioned a team of experts under Dr. George Govier to study all critical aspects of marketing B.C.'s natural gas, both inside and outside the province. Recognizing that there are no short-term solutions, the study group focused on changing the system to prepare for the future.

   The resulting study, A Report on the Marketing of British Columbia's Natural Gas, contains recommendations which will lead to a dramatic change in the province's natural gas industry. However it will require the co-operation of all parties involved, to ensure that the changes are implemented wisely and efficiently.

A REPORT ON THE MARKETING OF BRITISH COLUMBIA'S NATURAL GAS

DECISIONS AND COMMENTS

September 1983

A REPORT ON THE MARKETING OF BRITISH COLUMBIA'S NATURAL GAS

DECISIONS AND COMMENTS

September 1983

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A PREAMBLE

This paper summarizes the principal decisions made by the government of British Columbia in the matter of restructuring British Columbia's natural gas industry. These decisions have been taken after an assessment of recommendations made to the government by a Study Group chaired by Dr. George W. Govier in its report entitled "A Report on the Marketing of British Columbia's Natural Gas". Accordingly, this paper must be read in conjunction with the report, ideally after an initial reading of the report in its entirety.

The government acknowledges the valuable assistance provided by the Study Group. The government was especially pleased with the approach employed by the Study Group in developing its recommendations. The application of marketing and pricing principles and policies to the subject area, coupled with a comparison of procedures used in other provinces, produced a comprehensive, cohesive and well structured review. The government believes the Study Group has addressed, in principle, all major factors relevant to the Province's gas industry.

Generally, the government agrees with the report's recommendations and has decided to accept and is prepared to implement many of the Study Group's recommendations directly. Where such is the case, this paper refers only briefly to the factors supporting the recommendation. Additional detail is available in the report.

The government has not accepted all of the Study Group's recommendations. Some recommendations have been modified for

implementation. The modified decisions do, however, remain consistent with the marketing and pricing principles and policies which guided the Study Group.

In a few instances recommendations have been rejected. Reasons for these rejections are provided within.

Finally, the government has postponed making decisions on certain recommendations, identified herein, pending receipt of written comments from interested parties. Interested parties are invited to submit their views in writing to the Minister of Energy, Mines and Petroleum Resources (the Minister) on or before October 31, 1983. Written submissions should be sent to:

The Honourable Stephen Rogers
Minister of Energy, Mines
and Petroleum Resources
Legislative Buildings
Victoria, British Columbia
Canada V8V 1X4

(Telex: 049-7135)

It is the intention of the government to expeditiously implement those decisions already taken, and those yet to be taken following receipt and review of comments from interested parties. It is anticipated that the restructuring of the system can be completed and the new system in place within a year.

The report is released as received in February, 1983. It is acknowledged that situations and numbers described in the report have changed, however none of these changes have affected the essence of the conclusions drawn and recommendations made.

This paper is organized so as to reflect the key areas in which recommendations have been made: 1) institutional and 2) financial. Where appropriate, a secondary grouping of decisions has been undertaken to tie together recommendations that impact key participants in the Province's gas industry.

To facilitate easy referencing the recommendation numbers, as set out in the report's Executive Summary, have been placed in the right hand margin alongside the discussion noting how the government has decided to deal with them.

A chart summarizing the decisions taken by the government with respect to the recommendations is located at the end of the text in this report.

B INSTITUTIONAL DECISIONS — Rec. No.

B.1 **The Role of the British Columbia Petroleum Corporation (BCPC)** - The government agrees that the BCPC must fulfill its current contractual obligations to producers and therefore accepts recommendations 8 and 19 ensuring that existing rights for existing gas contracts are maintained. As Westcoast Transmission Company Ltd.'s (Westcoast) cost of service is borne by producers and the people of British Columbia, the government believes it imperative that the BCPC continue to represent the Province's interests before the National Energy Board (NEB). The government therefore accepts recommendation 20 that the BCPC continue monitoring Westcoast's cost of service and making appropriate submissions to the NEB. — *8, 19, 20*

One of the government's main objectives is to reduce its direct participation in the natural gas industry. In rejecting, at this time, recommendation 21, which would have given the BCPC the opportunity to purchase future contracted gas[1], the government is taking positive action to return the industry to the private sector. This decision does not preclude the ability of the government to have the BCPC buy gas should that become desirable or necessary in the future. Written comment is requested on the conditions under which BCPC should once again purchase gas. — *21*

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1 The term 'future contracted gas' refers to gas which is obtained for the purpose of providing a service for which a new or revised sales contract will be required.

DECISIONS AND COMMENTS

ERRATUM

Page 5, third paragraph dealing with Recommendations 4(a), 10: delete last sentence (All other. . .eligible buyer.)

The matter of eligibility is dealt with in Section B.4.

Rec. No.

Even though the BCPC will no longer be the sole purchaser of gas, there is still a need to protect the Province's constitutional jurisdiction over this important resource. To secure this jurisdiction, the government accepts recommendation 22 that the BCPC take a temporary ownership position for all natural gas. 22

B.2 **Producers' Role** - The government agrees with the Study Group that the current marketing arrangement for natural gas in British Columbia is too restrictive and that a more effective approach is to allow producers the opportunity to gather, process, transmit and market future contracted gas. The government therefore accepts recommendation 4(b) to allow producers to build and/or own transmission and/or processing facilities. 4(b)

The government accepts recommendations 4(a) and 10 with the modification that producers are allowed to sell raw or marketable gas to any <u>eligible</u> buyer. While the government's decision stated in Section B.1 excludes the BCPC from the marketing of future gas at this time, no decision has yet been made on whether producers may sell gas directly to Westcoast. This is discussed further in Section B.3 (Westcoast's Role). All other potential buyers including U.S. importers are <u>eligible</u> buyers. 4(a), 10

To further reduce restrictions on the natural gas industry, the government accepts recommendation 9 that producers be permitted direct involvement in the marketing of by-products from the future contracted gas stream. 9

Rec. No.

B.3 **Westcoast's Role** - The government must be careful in restructuring British Columbia's natural gas system to protect current arrangements and obligations. Therefore, the government accepts recommendations 3, 12 and 13 that Westcoast retain its existing rights with respect to existing contracts and existing pipeline and processing facilities. 3, 12, 13

Westcoast is currently committed to purchase gas from Alberta and the Northwest Territories for export to the United States. In order to protect British Columbia producers against any such future commitments, the government accepts recommendation 1 thereby agreeing to seek guarantees from Westcoast, over and above those that exist in the Westcoast/BCPC agreement, that British Columbia producers are offered first purchase contracts. 1

With respect to the current regulation of Westcoast, it is clear that interprovincial pipeline activities come under the jurisdiction of the NEB and the provincial government believes this to be appropriate. However, with respect to Westcoast pipeline activities that are intraprovincial in nature, the government believes provincial regulation to be appropriate. Therefore, the Province accepts, in principle, recommendation 18 which would see Westcoast's intraprovincial activities brought under provincial control. 18

The government acknowledges the jurisdictional authority of the NEB as it impacts the above recommendation and certain others following. It is the intent of the government to work with all relevant parties to attain

Rec. No.

the implementation of those recommendations accepted by the government which require assistance and/or approval from those parties.

Having accepted recommendation 4 which permits producers to sell to eligible buyers, the government also accepts recommendation 14, i.e. that Westcoast act as a common carrier and processor for future contracted gas, which is obviously critical to making recommendation 4 workable. The government notes again that the implementation of recommendation 14 presently rests with the NEB. Consequently until such time that the provincial government has this ability, it will support those parties making submissions before the NEB to have Westcoast act as a common carrier and processor. 14

A decision has not yet been made on recommendation 15 which would give Westcoast "a non-exclusive right to purchase, gather, process and market future contracted gas and to receive commissions and fees for gathering, processing or marketing such gas that would reflect the true cost of service of transporting and processing the raw gas". 15

While the government endorses the right for Westcoast to gather and process future contracted gas it requests written comment on the other aspects of this recommendation.

B.4 **New Market Development** - In keeping with the government's move toward a freer market economy, the

Rec. No.

government accepts recommendation 32 to allow for new marketing efforts, but with some modifications. 32

(a) **International** - Within the context of recommendation 30, which will establish the bounds of the international border price, the government immediately authorizes direct industrial sales by the producer for future contracted U.S. pipeline exports and for the Western LNG Project.

The government, however, notes the difference between pipeline and LNG sales and will therefore treat each differently. The return to producers and the Province is expected to be less from LNG sales than from pipeline sales because of the higher costs incurred by an LNG project. The Province, therefore, will assess producers a royalty on gas sold to the LNG project based on the higher of the transaction price or a minimum deemed price which is yet to be determined. In addition, sales to the Western LNG Project will be excluded from the export flowback scheme (i.e. volumes of gas sold to the Project and the price received for such sales will not be taken into account in calculating and distributing the export flowback).

(b) **Domestic Industrial** - Direct sales may be made to eligible purchasers but only through the facilities of the appropriate utility company. Sales made directly to an industrial customer at a discount from the wholesale price will be subject to the following conditions:

1. Sales made at a discount will not be eligible for export flowback (i.e. these volumes of gas will not be taken into account in calculating and distributing the flowback).

2. Royalty will be assessed on the actual (discounted) transaction price down to a minimum level to be determined.

On the above basis the government immediately authorizes direct industrial sales for an ammonia/urea project.

The criteria used to determine the minimum deemed prices for royalty purposes will distinguish between gas directed to domestic or export markets.

In approving direct sales for LNG and ammonia/urea, the government has taken into consideration the fact that these projects represent new gas uses and that they will be located on new pipeline facilities, having minimum impact on existing transmission and distribution facilities.

The approval of additional direct sales will be considered by the government in the future. The government therefore seeks written comment from interested parties before establishing the criteria that will be employed to determine eligibility for direct industrial sales for other than the ammonia/urea, LNG projects and U.S. pipeline exports.

Rec. No.

(c) **Other Markets** - The government accepts recommendation 33, undertaking to continue developing new markets (e.g. for compressed natural gas), to protect existing markets, to review the Gas Extension Assistance Program and to continue emphasizing further processing of natural gas. 33

B.5 **Out of Province Supply** - The government does not believe that Alberta gas should continue to displace British Columbia gas in our traditional U.S. export market and therefore accepts recommendation 2 that alternatives be found for Alberta gas entering into northeastern British Columbia. Recommendation 29 is taken under advisement by the government. 2 29

B.6 **Straddle Plants** - The government believes that exclusive provincial jurisdiction would help facilitate the development of a petrochemical industry in British Columbia. Therefore it accepts, in principle, recommendation 5 which would give the Province exclusive jurisdiction over the construction and operation of straddle plants in British Columbia. The government will work towards obtaining provincial jurisdiction of any straddle plant. 5

B.7 **Storage** - The economic benefits associated with underground storage can be significant. In view of future projects such as Vancouver Island Pipeline, Western LNG and an ammonia/urea plant, the government believes it is important to begin developing storage

Rec. No.

capacity now in order to maximize the efficiency of the existing system when these additional demands materialize. The government invites comments on recommendations 6 and 7 as to the development of suitable underground storage in the Fraser Valley. 6, 7

B.8 **Gas Marketing Committee** - The government notes recommendation 11 and is prepared to participate on a committee to provide advice respecting gas marketing, if such a committee is desired by industry. Written comment is sought from interested parties. 11

B.9 **Take-or-Pay** - The insertion of a take-or-pay provision in GL-41 reflects provincial government policy. The government therefore accepts recommendation 16 in principle, to request the NEB to modify the terms of export licence GL-41 in order that more appropriate commitments are made by the importer. The Province will present its position at the NEB's "show cause" hearing early in 1984. 16

B.10 **Westcoast Method of Taxation** - The government is pleased to note that, following interventions before the NEB by the BCPC seeking a change in the method of taxation applied to Westcoast, recommendation 17 has been effected by the recent NEB decision requiring Westcoast to use a flowthrough method of taxation. 17

B.11 **Energy Units** - The government believes that, for consistency within the natural gas industry, field and wholesale prices should be expressed in Standard International (S.I.) units and therefore accepts recommendation 23. 23

C FINANCIAL DECISIONS — Rec. No.

C.1 **Royalties** - The government acknowledges the need for a pricing system which provides producers with a measure of predictability and permanence. The provincial government also believes it appropriate that producers share in the risks and rewards resulting from changes in gas prices and sales volumes. Therefore the government accepts for implementation recommendations 34, 35 and 36 that an explicit royalty system be applied to all gas produced in the province including gas sold to the BCPC under existing contracts. *34, 35, 36*

The new formula-based, explicit royalty system is unique in that it levies higher royalties on gas that is cheaper to find and produce and lower royalties on gas that is more expensive to find and produce. The system also levies lower royalties while a well is new, allowing producers a more rapid payback in the early years and then a more gradual payback as the well matures.

The BCPC will, at the earliest possible date, begin to renegotiate existing contracts to allow for the inclusion of the royalty system.

With respect to royalty collection and the inclusion of the cost of service and by-product revenues, the government accepts recommendations 37 and 38 respectively, and asks for written comments from interested parties as to how this can be best accomplished. *37, 38*

Rec. No.

C.2 **Wholesale Price** - The government recognizes that the health of the natural gas industry is predicated on predictability and the level of netbacks. In turn, the producer netbacks depend upon the wholesale price and the level of royalty. Ultimately, the end user requires predictability for investment decisions.

A wholesale pricing policy that ties the price of gas to oil provides a measure of predictability and a policy that is readily understood by industry and consumers alike. In addition, such a pricing policy would ensure an obvious competitive advantage for natural gas relative to oil which is a fundamental objective of the province's energy policy. Therefore the government accepts with modification recommendations 24, 25 and 26, and will implement a long-term wholesale pricing policy which links the price of natural gas to the refinery gate price of oil at Vancouver. 24, 25, 26

Instead of immediately moving the average wholesale price to equal the Alberta border price for the remainder of 1983 and 1984 and then phasing in to 65 percent of the cost of crude by 1990, the wholesale price will be phased in directly to a target level of 65 percent of the energy equivalent cost of crude oil at the Vancouver refinery gate by 1990.

The following schedule shows the projected average wholesale price to 1990 based on the 65 percent tie and the Ministry of Energy, Mines and Petroleum Resources' current projection of oil prices.

Rec. No.

Projected Provincial Average Wholesale Price

	Crude Oil at Vancouver Gate Refinery[1] ($/GJ)	Phase-in Tie to 65% (%)	Natural Gas Wholesale Price ($/GJ)
Current	5.66	41.80	2.22[2]
1984	5.43	45.11	2.44[2]
1985	5.48	48.43	2.65
1986	5.86	51.74	3.03
1987	6.15	55.06	3.39
1988	6.45	58.37	3.76
1989	6.94	61.69	4.28
1990	7.81	65.00	5.08

1 Net of Canadian Ownership Special Charge.

2 Includes an allowance for the Natural Gas and Gas Liquids Tax.

C.3 **Retail Prices** - Recommendations 43, 44 and 45, regarding the consumer subsidy or rebate, were made obsolete by the government's August 1, 1983 decision to raise the wholesale price and eliminate the subsidy on domestic sales. 43, 44, 45

Rec. No.

The government intends to maintain regulation of retail prices through the British Columbia Utilities Commission and therefore accepts recommendation 46, requiring the Commission to continue determining retail rates at levels equal to the wholesale price plus the appropriate distribution costs. 46

The retail price implications for B.C. Hydro residential consumers of a wholesale price phased to 65 percent of crude by 1990 are projected to be as follows:

Projected Residential Retail Price

	Retail Price ($/GJ)	Increase/(Decrease) (%)
Current	4.49	
		(0.4)[1]
1984	4.47	
		7.2
1985	4.79	
		11.3
1986	5.33	
		9.8
1987	5.85	
		8.7
1988	6.36	
		11.2
1989	7.07	
		14.4
1990	8.09	

---

1 Pacific Northern Gas and Inland Natural Gas are projected to experience price increases of 10 percent from the current date to 1984. The B.C. Hydro prices are restrained due to the benefits expected to accrue from the use of storage beginning in this period. Increases post 1984 are projected to be comparable for all utilities.

Rec. No.

C.4 **Field Prices**

(a) **Producer Selling Price** - The government accepts recommendation 27 thereby designating the price at the gathering point for all marketable gas sold intraprovincially, with the exception of gas sold at a discount, to be the system average wholesale price less the appropriate cost of service. 27

(b) **Export Flowback** - The government believes that the export flowback provides for the equitable distribution of profits from the export market. Therefore it accepts recommendation 28 to ensure that the incremental revenue derived from both existing and future U.S. export sales (at prices greater than the domestic price) is shared by all producers (except those selling gas at a discount) ratably according to their production. The export flowback will be administered by the BCPC. 28

C.5 **Equivalent Netbacks** - The provincial government recognizes that the level of future drilling activity in this province depends, in part, upon the level of netbacks. Therefore the government accepts in principle recommendation 42 that netbacks be increased in order to stimulate drilling activity in the province. 42

While British Columbia netbacks have historically been low relative to Alberta, the government acknowledges that it must provide competitive netbacks to ensure a healthy level of industry activity in British Columbia.

Rec. No.

Currently, British Columbia's netbacks are estimated to average $0.37/GJ for pre 1973 gas and $0.50/GJ for post 1973 gas. These are competing with Alberta netbacks which average $0.53/GJ for pre 1973 gas and $0.75/GJ for post 1973 gas (see Table 1 for detailed calculations).

Upon implementation of the proposed royalty and wholesale pricing system in British Columbia, the gap in netbacks will narrow considerably. Under the new system, it is estimated that British Columbia's netbacks will move immediately to $0.42/GJ for pre 1973 gas and $0.57/GJ for post 1973 gas (see Table 2 for detailed calculations). By 1985, it is expected that British Columbia netbacks will average at 80 percent of the value of Alberta netbacks. Further, as the wholesale price phases in to the 65 percent target level of oil, the gap is likely to narrow even more.

C.6 **Royalty Holiday** - The government believes that the increase in netbacks that will result from the wholesale pricing policy decision offsets the need for a royalty holiday and therefore rejects recommendation 41 that there be a 24-month royalty-free period for eligible wells drilled in the next 12 months. 41

C.7 **Provincial Taxes** - The government accepts recommendation 39 to continue to provide an income tax rebate for royalty payments. 39

Rec. No.

C.8 **Federal Taxes** - The government of British Columbia has objected, in principle, to the federal Canadian Ownership Special Charge (COSC) and the Natural Gas and Gas Liquids Tax (NGGLT) since their inception. Therefore the government accepts recommendation 40 that the Province continue to urge the federal government to abandon these taxes. With the NGGLT currently being phased out, the Province will concentrate its efforts on effecting the abandonment of the COSC. 40

C.9 **Export Pricing System** - The government accepts recommendation 30 and urges the federal government to replace the present export pricing system with a system which would allow producers to negotiate with export buyers on an arms-length basis. The terms of such a sale would be subject to provincial and federal government approval. 30

C.10 **Tariff Structure** - The government believes the general approach to rate design currently employed in the Province to determine demand/commodity charges for each distributor is directionally sound and correct. However, the current demand/commodity rates on the Westcoast system no longer reflect the true costs of delivered gas to distributors. Therefore the government accepts recommendation 31 that the British Columbia Utilities Commission be instructed to review and establish an appropriate tariff structure, following the NEB hearing into Westcoast's method of regulation. 31

SUMMARY OF DECISIONS TAKEN AS TO THE RECOMMENDATIONS

Recommendation	Decision
1	Accepted
2	Accepted
3	Accepted
4	4(a) Accepted with modification, comment solicited; 4(b) Accepted
5	Accepted in principle
6	Comment solicited
7	Comment solicited
8	Accepted
9	Accepted
10	Accepted with modification, comment solicited
11	Comment solicited
12	Accepted
13	Accepted
14	Accepted
15	Comment solicited
16	Accepted in principle
17	None - already effected through NEB decision
18	Accepted in principle
19	Accepted
20	Accepted
21	Rejected, comment solicited
22	Accepted
23	Accepted
24	Accepted with modification
25	Accepted with modification
26	Accepted with modification
27	Accepted
28	Accepted
29	Under advisement
30	Accepted
31	Accepted/BCUC hearing required
32	Accepted with modification
33	Accepted
34	Accepted
35	Accepted
36	Accepted
37	Accepted - comment solicited
38	Accepted - comment solicited
39	Accepted
40	Accepted
41	Rejected
42	Accepted in principle
43	None - obsolete
44	None - obsolete
45	None - obsolete
46	Accepted

TABLE 1

Calculation of the Current Producer Netback
(at full taxes) in Alberta

	$ per gigajoule (GJ)		
	Old Gas	New Gas	Note
Total Revenues	3.481	3.481	1.
Field Operating Costs	.168	.168	2.
Processing Costs	.477	.477	3.
Total Royalties Payable	1.160	.974	4.
PGRT	.340	.340	5.
PGRT Credit	(.020)	(.020)	6.
Federal Corporate Tax	.785	.785	7.
Provincial Corporate Tax	.184	.205	8.
Netback before Incentives	.387	.552	
Incentives:			
Exploratory Programs	-	0.06	
Average Long Term Royalty Tax Credit	0.06	0.06	9.
Average Low Productivity Well Adjustment	0.08	0.08	10.
Total Equivalent Netbacks	0.53	0.75	

Notes:

1. Total revenues include marketable gas and gas by-products. The marketable gas revenues are estimated to be $2.617/GJ. The by-product revenues as a percent of marketable gas revenues are: propane 7.2 percent, butane 6.2 percent, pentanes plus 13.0 percent, sulphur 6.6 percent. These percentages were estimated using data from the ERCB's monthly statistics for January, February, and March 1982. The revenues used were:

Marketable Gas	2.617
Propane	0.188
Butane	0.163
Pentanes Plus	0.340
Sulphur	0.173
	3.481

2. Field operating costs were assumed to be the same as in British Columbia. There is some evidence to suggest that these costs should be lower in Alberta than in British Columbia, but there is a lack of supporting factual material.

3. Processing costs used are the estimated value of the average gas cost allowance for 1981, $.40/GJ, inflated to give the 1983 value of $0.477/GJ. The full gas cost allowance is used rather than just the operating cost portion, as it is the return to exploration and development investment that the netback should represent and not investment in the gas plant (to make it comparable to the netback calculated for British Columbia).

4. Royalties payable may be calculated as follows. First gross royalties are calculated according to Alberta regulations. Given the above revenues, gross royalties will be:

	Old	New
Marketable Gas	1.070	0.855
Propane	0.057	0.057
Butane	0.049	0.049
Pentanes Plus	0.139	0.139
Sulphur	0.029	0.029
Total	1.344	1.129

This gives an average royalty rate on old gas of .3861 (i.e. 1.344 ÷ 3.481) and an average royalty rate on new gas of .3243 (i.e. 1.129 ÷ 3.481). The total royalties payable are then calculated according to the formula

$$TRP = ARR \times (TR - GCA)$$

where TRP = Total Royalties Payable
ARR = Average Royalty Rate
TR = Total Revenue
GCA = Gas Cost Allowance

Using this, the total royalties payable on old gas are 1.160, and on new gas are 0.974.

5. The PGRT on both old and new gas may be calculated as follows:

Total Revenues	3.481
Less Operating and Processing Costs	0.645
Net Price	2.836
Less 25 percent Resource Allowance	0.709
Taxable Base	2.127

The PGRT is 16.00 percent of the taxable base or 0.340.

6. The PGRT credit is an annual deduction of up to $250,000 against the PGRT liabilities of a company. It is estimated that this credit should be worth about 2¢ per GJ on average.

7. For a fully taxable producer, federal corporate income tax is 36.9 percent (i.e. 36 percent plus the 2.5 percent surtax) of the taxable base as shown in 5. above, or .785.

8. Provincial corporate tax for a fully taxable producer may be calculated:

	Old	New
Total Revenues	3.481	3.481
Less Operating and Processing Costs	0.645	0.645
Less Total Royalties Payable	1.160	0.974
Taxable Base	1.676	1.862

where the tax rate on the base is 11 percent giving taxes payable on old gas of $.184 and on new gas of 0.205.

9. The royalty tax credit has been raised significantly for 1982 and 1983, but is intended to return to its previous levels for 1984 and thereafter. Adhering to the policy of matching long term incentives with netbacks, but not short term incentives, the royalty tax credit for gas is estimated to be worth about $170 million or $.06 per GJ.

10. Alberta provides a royalty reduction for wells producing under 560 GJ per day. The average value of this reduction is estimated to be about $0.08 per GJ.

Table 2

Derivation of Netbacks Upon Implementation of New British Columbia Royalty System

British Columbia Gas Netback Estimates
(at full taxes $/gigajoule)

	Pre November 1973*	Post November 1973	Note #
Total Field Price	2.066	2.066	1.
Field Operating Costs	0.173	0.173	2.
Royalty	0.542	0.356	3.
PGRT	0.227	0.227	4.
PGRT Credit	(0.020)	(0.020)	5.
Federal Corporate Tax	0.511	0.511	6.
Provincial Corporate Tax	0.216	0.246	7.
Netback	0.417	0.573	

* November/73 is date currently used to distinguish 'old' and 'new' gas.

Notes:

1. The total field price of $2.066 per GJ is based on implementation of the wholesale pricing policy to phase in the wholesale price to 65 percent of crude oil at the Vancouver refinery gate.

2. These costs are the strict cash out-of-pocket expenses necessary to get gas into the Westcoast gathering system. The value given here represents a number estimated by the BCUC in 1980 ($.14 per Mcf based on submissions to their field price inquiry) which was inflated to arrive at the figure shown.

3. Royalty payable is based on the new royalty formula and cost related factors. The applicable royalty rates are 26 percent for pre November 1973 gas, and 17 percent for post November 1973 gas, derived from the average values given in Appendix 7 of the report and adjusted for price.

4. The PGRT on all gas may be calculated as follows:

	Total Field Price	2.066
Less:	Operating Costs	0.173
	Net Price	1.893
Less:	25% Resource Allowance	0.473
	Taxable Base	1.420

The PGRT is 16% of the taxable base, or 0.227.

5. The federal government currently allows an annual credit of up to $250,000 against the PGRT liability of a corporation. This credit has been estimated to be worth about $0.02 per GJ on average.

6. For a fully taxable producer, federal corporate income tax is 36 percent of the taxable base as shown in 4. above, or 0.511.

7. Provincial corporate tax for a fully taxable producer may be calculated:

	Pre November 1973 ($/GJ)	Post November 1973 ($/GJ)
Total Field Price	2.066	2.066
Less: Operating Costs	0.173	0.173
Less: Royalties	0.542	0.356
Taxable Base	1.351	1.537
Taxes Payable at 16 Percent	0.216	0.246

Province of British Columbia

NEWS RELEASE

SUMMARY OF MAJOR DECISIONS

INSTITUTIONAL DECISIONS

Producers' Role

With respect to future contracted gas, producers have the right to sell gas to any eligible buyer, to build and own transmission and processing facilities and to remove by-products from the gas stream.

New Market Development

The government immediately authorizes direct sales by the producer for future contracted U.S. pipeline exports, for the Western LNG Project and for an ammonia/urea project. Approval of additional direct sales will be considered once eligibility criteria has been established. The government will review written comments from interested parties before establishing these criteria.

BCPC's Role

The BCPC will maintain its existing rights for existing gas contracts, renegotiate existing contracts to allow for the inclusion of the royalty system, take a temporary ownership position for all natural gas, administer the export flowback, and continue monitoring Westcoast's cost of service. The BCPC has not been granted the right to purchase future contracted gas at this time; comments have been solicited from interested parties.

Westcoast's Role

Westcoast will maintain its existing rights with respect to existing contracts and existing pipeline and processing facilities and, will be requested to act as a common carrier and processor for future contracted gas. The government has decided to postpone its decision on granting Westcoast the right to purchase and market future contracted gas until receipt and review of written comments from interested parties.

Storage

The government invites comments respecting the development of suitable underground storage in the Fraser Valley.

FINANCIAL DECISIONS

Wholesale Price

The government has accepted a long-term wholesale pricing policy which links the price of natural gas to the refinery gate price of oil at Vancouver. The wholesale price will be phased in directly to a target level of 65 percent of the energy equivalent cost of crude at the Vancouver refinery gate by 1990.

Retail Price

The BCUC will continue to determine retail rates at levels equal to the wholesale price plus the appropriate distribution costs.

Producers' Selling Price

The price at the gathering point for all marketable gas sold intraprovincially, with the exception of gas sold at a discount, will be the system average wholesale price less the appropriate cost of service.

Export Flowback

The incremental revenue derived from both existing and future U.S. export sales (at prices greater than the domestic price) will be shared by all producers (except those selling at a discount) ratably according to their production.

Royalties

An explicit royalty system will be applied to all gas produced in the Province including gas sold to the BCPC under existing contracts. Implementation details, such as royalty collection and the inclusion of the cost of service and by-product revenues, will be released following receipt and review of comments from interested parties.

Equivalent Netbacks

The government recognizes the importance of producer netbacks to the gas industry and has chosen a wholesale pricing policy and royalty system which will provide increased netbacks for British Columbia producers, competitive with netbacks in Alberta.

Export Pricing System

The government supports the replacement of the present pricing system with a system which allows producers to negotiate with export buyers on an arms-length basis. The terms of such a sale would be subject to provincial and federal government approval.

Tariff Structure

The BCUC will be instructed to review and establish an appropriate tariff structure that reflects the true costs of delivered gas to distributors, following the NEB hearing into Westcoast's method of regulation.